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Alternative Interior to Lower Mainland
Transmission Reinforcement Sequences

Kelly Lake to Cheekye Substation Second 500 kV Transmission Line

March 1991

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System Transmission Planning Department
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TABLE OF CONTENTS

1. EXECUTIVE SUMMARY 1

2. INTRODUCTION 3

3. STUDY CRITERIA 4
   - 3.1 Technical Criteria 4
   - 3.2 Economic Criteria 4

4. METHODOLOGY 5
   - 4.1 Powerflow Basecases 5
   - 4.2 System Additions to Increase Thermal Limits 5
   - 4.3 System Additions to Increase Voltage Stability Limits . 5
   - 4.4 System Losses 5
   - 4.5 Technical and Economic Comparison 6
   - 4.6 Sensitivity Studies 6

5. ASSUMPTIONS : 6
   - 5.1 Technical 6
     - 5.1.1 Powerflow 6
     - 5.1.2 Thermal Capability 8
     - 5.1.3 Voltage Stability 8
     - 5.1.4 Transient Stability 8
     - 5.1.5 Calculation of System Losses 8
   - 5.2 Economic 9
     - 5.2.1 Electricity Values 9
     - 5.2.2 Loss Factor 9
     - 5.2.3 Discount Rate 9
     - 5.2.4 Direct Cost Estimates 9
     - 5.2.5 Burrard Thermal Generation 9

6. STUDY RESULTS 10
   - 6.1 SEQUENCE 1 10
     - 6.1.1 Staging (Figure 3-1; Appendix 3): 10
     - 6.1.2 Pre-outage Power Flows 10
     - 6.1.3 Outage Powerflows 11
     - 6.1.4 Voltage Stability 11
     - 6.1.5 Line Losses 12
   - 6.2 SEQUENCE 2 12
     - 6.2.1 Staging 12
     - 6.2.2 Pre-outage Power Flows 13
     - 6.2.3 Outage Powerflows 13
     - 6.2.4 Voltage Stability 14
     - 6.2.5 Line Losses 14

7. ECONOMIC ANALYSIS 14

8. SENSITIVITY STUDIES 15
   - 8.1 Discount Rate 15
   - 8.2 Electricity Value 15
   - 8.3 Loss Factor 16
   - 8.4 5L46 Direct Cost 16
   - 8.5 Indefinite Deferral of 5L46 16

8.6 Downstream Power Benefits 16

9. OTHER CONSIDERATIONS 17

10. CONCLUSIONS 19
10.1 Technical 19
10.2 Economic 19

11. RECOMMENDATIONS 21

REFERENCES

APPENDICES

1. POWERFLOW ASSUMPTIONS

2. PRE-OUTAGE POWERFLOWS

3. DEVELOPMENT SEQUENCES

4. OUTAGE POWERFLOWS (CURRENT)

5. VOLTAGE STABILITY STUDY RESULTS

6. LINE LOSS STUDY RESULTS

7. ECONOMIC ANALYSIS

ALTERNATIVE INTERIOR TO LOWER MAINLAND TRANSMISSION REINFORCEMENT SEQUENCES

1. EXECUTIVE SUMMARY

This report investigates alternative long-term development plans for the bulk transmission system serving the Lower Mainland and Vancouver Island region, and recommends that BC. Hydro should:

1. Build a second series compensated 500 kV line from Kelly Lake Substation to Cheekye Substation (5L46) for service in 1996, the earliest in-service date.

2. Determine the preferred system reinforcement for 1995/96 winter peak load.

3. Determine if an SVC or a 65% series compensated system is the best system reinforcement for 1997.

4. Carry out detailed planning studies to determine the best reinforcement alternative for the eastern side of the Interior to Lower Mainland grid. Start environmental and route investigation studies for the Nicola to Meridian 500 kV transmission line (5L83).

The first study, Reference [1], showed that the BC Hydro Int-LM 500 kV transmission grid requires reinforcement by the 1995/96 winter peak to avoid the risk of single-contingency voltage collapse.

The second study, Reference [2], evaluated approximately 35 reinforcement options and recommended that the following options be considered for developing alternative long-term Int-LM reinforcement plans:

1. Additional Int-LM 500 kV transmission lines;
2. Additional static var compensators (SVC's);
3. Increased series compensation of existing Int-LM 500 kV lines;
4. New series compensation on existing 500 kV lines;
5. Sectionalizing existing Int-LM 500 kV lines at a switching station near Ruby Creek (not used).

This third study investigates the effectiveness of the above short-listed options when used together to form alternative long-term system development plans. The study compared, on the basis of reliability, cost, and planning flexibility, two extreme project sequences, both of which were required to meet BC Hydro's single contingency withstand system planning criteria; Sequence 1, with transmission options staged early, and Sequence 2, with transmission options deferred as late as possible by using relatively lower capital cost reactive equipment options. The two sequences are shown in Figures 3-1 and 3-2, Appendix 3.

This report makes the same load forecast and export schedule assumptions as was made in [1] and [2]. System resource addition and Downstream Power Benefit (DSB) delivery assumptions were based largely on the November 1990 proposed Resource Plan. A notable exception, however, is that Vancouver Island load growth after 2002 was assumed to be met by BC Hydro's IPP and self-generation programs for Vancouver Island. The studies in this report assume an equal split of returning DSB's between Ingledow and Selkirk substations.

Study results show that Sequence 2 is $9 million, or 13%, less economic than Sequence 1. This relationship is relatively insensitive to small changes in the long-term marginal cost of Electricity, the Int-LM transmission loss factor, and the 5L46 direct cost. However, an assumed discount rate more than 9% (basecase discount rate 8%) would make Sequence 2 more economic than Sequence 1. The sequence cost relationship would be sensitive to a major change in the DSB delivery assumption made in this report.

Sequence 1 provides the greatest planning and operating flexibility and makes use of proven and readily available technology.

This report recommends that 5L46 be used to reinforce the Peace side of the Int-LM grid in 1996 because it:

- has the shortest lead time of the transmission options;
- is relatively short and makes partial use of existing right-of-way;
- would be well utilized in both the near and far terms;
- would reinforce the 500 kV Supply to Vancouver Island.

A sensitivity study of 5L46 in-service date shows that indefinite deferral of 5L46 (i.e. no 5L46) in Sequence 2 increases Sequence 2 cost by $19 million, i.e. making it $28 million, or 40%, more expensive than Sequence 1 (5L46 as soon as possible). This report, therefore, concludes that 5L46 is economically inevitable.

2. INTRODUCTION

This report determines the effectiveness of the proposed Kelly Lake to Cheekye 500 kV #2 transmission line project (5L46), relative to other feasible reinforcement options, for both near and far-term future transmission system reinforcement.

Reference [1] showed that the BC Hydro Int-LM 500 kV transmission grid requires reinforcement by 1995[1] to avoid violating System Planning Criteria regarding single-contingency voltage collapse.

Reference [2] evaluated approximately 35 reinforcement options and recommended that the following additions be considered in this report for developing alternative long-term Int-LM reinforcement sequences:

1. Circuit 5L46 (KLY-CKY 500 kV #2)
2. Circuit 5L83 (NIC-MDN 500 kV #2)
3. Static var compensators (SVC's) at Interior and Lower Mainland 500/230 kV substations
4. Sixty-five percent series compensation of Int-LM lines
5. Ruby Creek Switching Station
6. Fifty-percent series compensation of 5L87 (KLY-NIC 500kV)

This report compares on the basis of reliability, cost, and planning flexibility, two alternate long-term development sequences. Sequence 1 starts with the "transmission" options, i.e. Kelly Lake to Cheekye No.2 and Nicola to Meridian No.2 500 kV transmission lines. Sequence 2 defers new transmission lines as long as possible in favour of "reactive" options, e.g. new and increased series compensation, SVC's, etc.

The balance of this report is organized as follows:

Section 3: Presentation of the study criteria that was used to construct the development sequences.

Section 4: Discussion of the study methodology including the basis for the economic comparisons.

Section 5: Discussion of the key technical and economic study assumptions.

Section 6: Presentation of the technical study results.

Section 7: Presentation of sequence costs.

Section 8: Discussion of economic study sensitivities.

Section 9: Presentation of considerations beyond the single-contingency criteria.

Section 10: Conclusions

Section 11: Recommendation of the next Int-LM reinforcement.

---

[1] assumes 122 MW of self-generation in the Lower Mainland by 1994

3. STUDY CRITERIA

General Transmission Planning Criteria is described in Report No. SP8707, July 1987.

3.1 Technical Criteria

The following technical criteria was used to verify the feasibility of the alternative sequences.

a) General

For all stressed conditions and all lines and equipment in service, the outage of any single element must not result in loss of load or generation. In addition, all system voltages and power flows must remain within emergency limits without requiring operator intervention.

b) Equipment Loading

The failure of a major 500 kV transmission line will not require disconnecting load or generation to alleviate an overload of any remaining line. In particular, the load on the remaining 500 kV lines must not exceed 3000 amperes (thermal limit of 500 kV substation buswork, circuit breakers, and line disconnect switches).

c) Voltage Stability

Adequate system voltage must be maintained after the single-contingency loss of one transmission element. See [1] for details of the BC Hydro Voltage Stability Criteria.

d) Transient Stability

The system must be electromechanically stable, without generation shedding, following a first-contingency three-phase fault at the most critical location in the system and followed by an unsuccessful high-speed auto-reclose.

e) Effect on Neighbouring Utilities

The BC Hydro transmission system is interconnected with other utilities of the Western Systems Coordinating Council (WSCC). BC Hydro must meet the WSCC Reliability Criteria. BC Hydro must plan and operate its transmission system so as to exclude the possibility that specified outages could cascade into neighbouring utilities.

3.2 Economic Criteria

Amongst the technically feasible reinforcement alternatives, that which has the least long-term sum of capital and operating cost, including the cost (or savings) of system losses, is preferred. When comparing the cost of alternatives, the discounted cash flow method is used to determine the net present value of all associated costs.

4. METHODOLOGY

The sequence analysis assesses whether 5L46 can be delayed and what the technical and economic implications are of such a delay. The methodology described in this section was used to develop the alternate sequences. Only the options recommended in [2] were considered.

4.1 Powerflow Basecases

Powerflow basecases were prepared to represent the BC Hydro system during the 1994/95, 2003/04, and 2013/14 peak loads of approximately 8700 MW, 10700 MW, and 13200 MW, respectively. The purpose of these three basecases was to account for the following system developments in the technical and economic assessments:

1995/96 - Initial violation of BC Hydro's Voltage Stability Criteria;
2003/04 - Complete return of the DSB's from BPA;
2013/14 - Last resource addition in the November 1990 proposed Resource Plan[2].

Maximum Peace and maximum Columbia generation cases were developed for each basecase. Only firm export schedules to West Kootenay Power (WKP) and Seattle City Light (SCL), and future maximum import from Alcan, were represented.

4.2 System Additions to Increase Thermal Limits

Checks were made during the development of each sequence to ensure that single-contingency line loadings (without remedial action) did not exceed 3000 amperes. Violations were remedied by transmission line or series capacitor additions.

4.3 System Additions to Increase Voltage Stability Limits

Single-contingency (without remedial action) voltage stability studies, using the network topology determined in Item 4.2, were done to stage additional reactive equipment. System voltage stability limits were determined using the linear interpolation procedure described in [1].

4.4 System Losses

Line losses will be different for the two sequences. Therefore, system losses were calculated for the following system peak loads:

1. 1994/95 (for Sequence 1 only);
2. 2003/04 (completion of the Lower Columbia Development (LCD) Resource Smart projects and DSB return);
3. 2013/14 (last resource addition in November 1990 proposed Resource Plan).

The line loss evaluation was based on the sum of the average incremental line losses over all of the lines in each sequence. The average incremental line loss is the product of the increment in peak megawatt

[2] This Resource Plan represents only one possible scenario. The Homathko generation development in the Resource Plan was assumed to be deferred well beyond 20 years.

loss, as provided by the powerflow study, and the loss factor of the Interior to Lower Mainland system. Only I^2R losses (conductor heating losses) are considered because other losses, such as corona and insulator leakage, are relatively small.

The peak megawatt loss calculation required that BC Hydro 500 kV buses be fixed at 525 kV then calculating the change in real power losses, with and without, the subject line. For the second 500kV line added in each sequence, the first 500kV line was assumed to be already in service.

Loss reduction due to 5L46 was calculated at maximum Peace generation while loss reduction due to 5L83 was calculated at maxmium Columbia generation.

4.5 Technical and Economic Comparison

After the sequences were established, their relative performance during single and multiple contingency outages was assessed.

The net present value cost in 1990 of each sequence was calculated based on 1991-2040 cash flows. The calculation included the relative savings in system losses of the two sequences.

4.6 Sensitivity Studies

Studies were done to determine the sensitivity of the sequence economics to a change in discount rate, long-term marginal cost of Electricity, loss factor, 5L46 direct cost, and indefinite deferral of 5L46. Sensitivity studies were not done to address the amount or location of DSB deliveries; however, a qualitative discussion is provided in Item 8.6.

5. ASSUMPTIONS

5.1 Technical

5.1.1 Powerflow

a) Based on the Fall 1990 Probable Load Forecast and the November 1990 proposed Resource Plan, both of which were presented in [1].

Notes:

1. The forecast of Probable peak load includes the total domestic load plus system losses at winter peak load, including the effect of the DSM and E+ programs.

2. The 2003 load level base cases included the major LCD Resource Smart projects while the 2013 load level base cases included all LCD projects.

3. An additional (third) unit was modelled at each of the Waneta[3] and Brilliant[4] expansions to account for the possibility that the final plant capacities might significantly exceed the presently selected 380 MW and 150 MW, respectively. This additional capacity is also meant to account for potential IPP and self-generation development in the South Interior, neither which has been explicitly modelled.

4. Burrard output of 122 MW was included as a proxy for the dependable capacity of 150 MW of near-term LM/VI self-generation.

5. BC Hydro is currently embarking on IPP and self-generation programs for Vancouver Island; therefore, this study assumed zero Vancouver Island net load growth after 2002.

6. Zero non-firm exports; approximately 700 MW import from Alcan (Kemano/Kemano Completion at or near full output).

b) **"P8700" Basecases**

The 8700 MW peak load level base cases[5], that are representitive of the mid-1990's system configuration, included:

- all lines and equipment in service;
- dependable winter generation in the Lower Mainland and Vancouver Island of 1138 MW;
- new facilities:
  - Dunsmuir +200/-100 Mvar SVC
  - 5L13 (WSN-KLY#3) and Skeena-Kitimat 230 kV #2
  - American Creek Series Capacitor Station
  - Nelway and Selkirk (WWP tie) phase shifters
  - Clayburn 500/230 kV Substation (no Puget ties)
- switched shunt capacitors are added to major transmission, area transmission, and distribution buses to maintain nominal pre-disturbance voltage and dynamic var reserve;
- a 160 MW IPP at Williston Substation (Taylor and Williams Lake IPP's);
- 150 MW of LM/VI self-generation (122 MW dependable).

c) **"P10700" Basecases**

In addition to the items included in the P8700 base cases, the P10700 base cases[6], that are representitive of a 10,700 MW peak load level and a mid-2000's system configuration, included:

---

[3] 190 MW per unit

[4] 75 MW per unit

[5] see Table 1-1; Appendix1 and Figures 2-1 and 2-2; Appendix 2

[6] see Table 1-2; Appendix 1 and Figures 2-3 and 2-4; Appendix 2

- Site C (900 MW);
- Lower Columbia Development Major Resource Smart Projects:
  - Keenleyside (240 MW)
  - Waneta Expansion (570 MW)
  - Brilliant Expansion (225 MW)
  - Seven Mile (202 MW)
- DSB import split evenly between Ingledow and Selkirk (100 MW in 1998, 600 MW in 1999, 1100 MW in 2003);[7]
- 138 kV cables to Vancouver Island (1L17/18) retired.

d) "P13200" Basecases

In addition to the items included in the P10700 basecases, the P13200 base cases[8], that are representitive of a 13,200 MW peak load level and a mid-2010's system configuration, included:

- Elaho (204 MW)[9];
- LCD Projects:
  - Border (275 MW)
  - Murphy/Duncan (300 MW)
- Lower Canyon (360 MW).

5.1.2 Thermal Capability

The ultimate 500 kV circuit thermal limit is the 3000 ampere continuous overload capability of the 500 kV substation buses, circuit breakers, and line disconnect switches.

5.1.3 Voltage Stability

Refer to [1] for assumptions regarding powerflow modelling for voltage stability studies. Voltage stability studies do not include representation of 2L1 (Bridge River-Cheekye 230 kV #1).

5.1.4 Transient Stability

Both sequences were assumed to be transiently stable for single-contingency disturbances, without generation shedding, given the relatively small pre-outage GMS-ING and SEL-ING phase angles.

5.1.5 Calculation of System Losses

1. Circuit 2L1 is represented in those loss powerflows which do not include 5L46;
2. Circuits 5L46 and 5L83 will use 469.53 mm^2 (927 MCM) Special four-bundle conductor;
3. SVC's incur approximately one megawatt of pre-outage losses;

---

[7] See Section 8 for a discussion of the effect of alternate DSB delivery assumptions.

[8] see Table 1-3; Appendix 1 and Figure 2-5 and 2-6; Appendix 2

[9] 60% of nameplate

4. No change in system losses after 2013 (i.e. after the last resource in the assumed Resource Plan comes on line).

5.2 Economic

5.2.1 Electricity Values

The assumed marginal cost of Electricity delivered to the Lower Mainland in 1990 dollars is shown in Table 7-2; Appendix 7. This table shows that Electricity values level out at 64 mills/kWh in 2002.

5.2.2 Loss Factor

The nominal Int-LM transmission loss factor of 0.60 was derived in [2]. This value includes allowance for secondary energy exports.

5.2.3 Discount Rate

A nominal 8% discount rate was assumed in the economic assessment of the alternatives.

5.2.4 Direct Cost Estimates

a) Circuit 5L46

The Probable cost estimate for 5L46 assumes an approximate 200 kilometre length and partial use of 2L1 right-of-way.

In Sequence 1, the Creekside II Series Capacitor Station cost estimates assume initial and ultimate ratings of 50% series compensation/2000 amperes and 65% series compensation/3000 ampere, respectively. In Sequence 2, the Creekside II initial and ultimate ratings are 65% series compensation/3000 amperes.

b) Circuit 5L83

The cost estimate for 5L83 assumes an approximate 250 kilometre length along a route which parallels 5L82 from Nicola to Meridian.

In Sequence 1, the American Creek III Series Capacitor Station cost estimates assume initial and ultimate ratings of 50% series compensation/2000 amperes and 65% series compensation/3000 ampere, respectively. In Sequence 2, the American Creek III initial and ultimate ratings are 65% series compensation/3000 amperes.

5.2.5 Burrard Thermal Generation

In the Sequence 1 economic analysis in Section 8, a one-year expense for operating Burrard Unit #5 at minimum output (40 MW) for dynamic var reserve in 1995/96 is included. This expense of $3.35 million is to firm up the Burrard gas supply based on a recent BC Hydro/BC Gas swing gas contract. It is assumed that there will be adequate gas pipeline capacity available over the 1995/96 winter peak load period for the required generation.

6. STUDY RESULTS

Single-contingency thermal capability and voltage stability studies were done for both sequences to ensure compliance with System Planning Criteria. Peak megawatt losses were recorded for each sequence at critical stages in system development for use in the economic analysis in Section 7.

The technical study results are included in the following appendices:

Appendix 2: System pre-outage powerflows
Appendix 3: Sequence drawings
Appendix 4: Single-contingency outage current loadings
Appendix 5: Single-contingency reactive power reserves
Appendix 6: System line losses

Figures 2-1 and 2-2 in Appendix 2 are pre-outage powerflows for the 1994 4-line (i.e. existing) Int-LM transmission system.

6.1 SEQUENCE 1

Sequence 1 uses the 5L46 and 5L83 transmission options at their earliest in-service dates to increase Int-LM transfer capability. Thereafter, new reactive equipment is added to keep positive single-contingency var reserve.

Note in this discussion that prudent loadings[10] ("soft" limits) of the 500 kV 50% series compensated lines are:

- 2.00 pu SIL[11](2000 MW/2300 amps) for 5L41 (KLY-CBN);
- 2.25 pu SIL (2250 MW/2600 amps) for 5L81/82/83 (NIC-ING/MDN);
- 2.50 pu SIL (2500 MW/2900 amps) for 5L42/46 (KLY-CKY).

6.1.1 Staging (Figure 3-1; Appendix 3):

Sequence 1

Addition	Year
1. Circuit 5L46 (KLY-CKY 500 kV #2)	1996[12]
2. Ingledow +200/-100 Mvar SVC	1997
3. Circuit 5L83 (NIC-MDN 500 kV #2)	1999
4. Nicola +300/-150 Mvar SVC	2004
5. Malaspina +300/-150 Mvar SVC	2007
6. Kelly Lake +300/-150 Mvar SVC	2009
7. 65% Series Compensation of Int-LM lines	2011
8. 50% Series Compensation of 5L87	2012

6.1.2 Pre-outage Power Flows

Powerflows, which assume all lines and equipment in service for

---

[10] See [6]

[11] Surge Impedance Loading (SIL) of an uncompensated 500 kV line is approximately 1000 MW.

[12] Earliest in-service date.

the 6-line system (i.e. includes 5L46 and 5L83), are shown in Figures 2-3 to 2-6; Appendix 2. In summary, at maximum Peace generation and zero non-firm export, the flows are reasonably shared amongst all the lines. At maximum Columbia generation, however, the flow on the Columbia lines in some cases more than doubles that on the Peace lines. The maximum pre-outage power flow is 1631 MW on 5L83 (Figure 2-6) which is within the soft limit described above. The maximum GMS-ING and SEL-ING pre-outage angles do not exceed 35 degrees.

Note in figures 2-3 to 2-6 that 5L46 transmits approximately 1150 MW at maximum Peace generation and 800-1000 MW at maximum Columbia generation. This shows 5L46 to be well utilized in both near-term and long-term system developments.

6.1.3 Outage Powerflows

Single-contingency outage currents for the Sequence 1 (6-line) system are shown in Figures 4-1 and 4-2; Appendix 4. Summary Table 4-1 in Appendix 1 shows that the maximum outage current is 2311 amperes on 5L83 (Figure 4-2) which is approximately 90% of the 5L83 soft limit and significantly below the 3000 ampere "hard" limit.

6.1.4 Voltage Stability

Figure 5-1 in Appendix 5 shows the single-contingency reactive reserve at each stage of Sequence 1 development. Along the abscissa are both the BC Hydro system peak load and the corresponding year when it will occur based on the load forecast assumptions. Note that, due to powerflow modelling limits, reactive additions shown after 2003 (10700 MW) represent BC Hydro's engineering judgement of single-contingency var reserve.

Highlights

1. Reference [1] concluded that Int-LM reinforcement will be required by the 1995/96 winter peak to maintain system reliability. However, the earliest in-service date for 5L46 is 1996. Therefore, Sequence 1 technical and economic analysis assumes the 1995/96 use of a Burrard unit at minimum output for dynamic var reserve.

2. Circuit 5L46 is added in 1996 because it increases the transfer capability on the Peace side of the grid, has a pay back in reduced system losses (i.e. is Power Smart), balances the loadings on the lines out of Kelly Lake, and reinforces the Vancouver Island Supply.

3. The Ingledow SVC is added in 1997 because it increases both the Peace and the Columbia transfer capabilities, comes after four years of operating experience with the Dunsmuir SVC, and is needed to provide single-contingency dynamic var reserve until 5L83 comes into service in 1999.

4. Circuit 5L83 is added in 1999 because it increases the transfer capability on the Columbia side of the Int-LM grid,

has a pay back in reduced system losses (i.e. Power Smart), and is needed in any event to increase the thermal capability of the Columbia side of the Int-LM grid.

5. Reactive additions after 1999 alternately increase the voltage stability limits on the Peace and Columbia sides of the Int-LM grid.

6. Circuit 5L87 is 50% series compensated in 2012 to converge both sequences by the end of the planning horizon.

Figure 5-3 in Appendix 5 shows how the voltage stability step increases provided by Sequence 1 keep pace with the growing Integrated System Probable peak load.

6.1.5 Line Losses

Powerflow losses were determined at the 1996 (5L46), 2003 (last DSB return and last major LCD Resource Smart project), and 2013 (last new resource in the 30 October 1990 proposed Resource Plan) stages of system development.

The Sequence 1 reduction in peak megawatt system loss, due to adding 5L46 and 5L83 to the existing 4-line system, is plotted in Figure 6-1; Appendix 6.

The changes in system peak megawatt losses, due transmission and non-transmission[13] additions, are included on Page 4 of Table 7-5; Appendix 7.

6.2 SEQUENCE 2

Sequence 2 uses non-transmission options as long as possible to increase Int-LM transfer capability. However, 5L83 will still be required to increase the thermal capability of the Columbia side of the Int-LM grid.

Note in the discussion below that prudent loadings of the 500 kV 65% series compensated lines are:

- 2.50 pu SIL (2500 MW/2900 amps) for 5L41 (KLY-CBN);
- 2.75 pu SIL (2750 MW/3200 amps) for 5L81/82/83 (NIC-ING/MDN);
- 3.00 pu SIL (3000 MW/3450 amps) for 5L42 (KLY-CKY).

6.2.1 Staging (Figure 3-2; Appendix 3):

Sequence 2

Addition	Year
1. Ingledow +200/-100 Mvar SVC	1995
2. 65% Series Compensation of Int-LM lines	1997
3. 50% Series Compensation of 5L87	1999
4. Kelly Lake +300/-150 Mvar SVC	2000

[13] one megawatt loss per SVC

5. Circuit 5L83 (NIC-MDN 500 kV #2) 2001
6. Malaspina +300/-150 Mvar SVC 2003
7. Nicola +300/-150 Mvar SVC 2005
8. Circuit 5L46 (KLY-CKY 500 kV #2) 2007

6.2.2 Pre-outage Power Flows

Powerflows, which assume all lines and equipment in service for the 5-line system (i.e. including 5L83), are shown in Figures 2-7 to 2-10; Appendix 2. All powerflows include 65% series compensation of 5L41/42 and 5L81/82/83, and 50% series compensation of 5L87.

At maximum Peace generation and zero non-firm export (Figures 2-7 and 2-9; Appendix 2), 5L42 flows are 60-70% higher than 5L41 flows. This is because of 5L42's extra requirement to supply a portion of the Vancouver Island load via Cheekye Substation. Nevertheless, the maximum 5L42 flow of 1734 MW in Figure 2-9 is only about 60% of its soft limit.

At maximum Columbia generation in Figure 2-8, the average flow on the Columbia lines is more than 150% that on the Peace lines. This inequality is partly due to reduced Int-LM impedance on the Columbia side due to addition of 5L83, 5L87 50% series compensation, and the 65% series compensation of Int-LM lines. This result implies some need to tune the increased compensation, the result of which may be less increase in Int-LM transfer capability than is shown in these studies. The maximum GMS-ING and SEL-ING pre-outage angles do not exceed 35 degrees.

6.2.3 Outage Powerflows

Single-contingency outage currents for the Sequence 2 are summarized in Table 4-2; Appendix 4.

Figure 4-3 shows that current on the Columbia side of the existing 4-line Int-LM system will exceed the 3000 ampere hard limit in 1998 for the single-contingency outage of 5L81 or 5L82 at maximum Columbia generation. Figure 4-4 shows that this can be relieved, even after Keenleyside comes into service, by series compensating 5L87. Therefore, 5L87 is series compensated in 1999 to defer 5L83 as long as possible.

Circuit 5L83 is required in 2001 because of the high single-contingency current loading shown in Figure 4-4, the growing DSB transfer through Selkirk in the period 1999-2003, and the possibility of significant South Interior IPP development.

The maximum 5L42 outage current is 2470 amperes, shown in Figure 4-5 in Appendix 4, for outage of 5L41 at maximum Peace generation. This is 72% of 5L42's soft limit and comfortably below the 3000 ampere hard limit.

In summary, the 5-line system with additional series compensation has adequate thermal capability to carry it through to the end of the System Plan in 2013.

6.2.4 Voltage Stability

Figure 5-2 in Appendix 5 shows the single-contingency var reserve at each stage of Sequence 2 development.

1. The Ingledow SVC is added in 1995 as a short lead-time option for increasing the single-contingency transfer capabilities on both the Peace and Columbia sides of the Int-LM grid.

2. Circuits 5L41, 5L42, 5L81, and 5L82 are 65% series compensated in 1997 to increase the single-contingency transfer capabilities of both the Peace and Columbia sides of the Int-LM grid.

3. Circuit 5L87 is 50% series compensated in 1999 to divert power towards Kelly Lake thereby avoiding single-contingency thermal overload of either 5L81 or 5L82 at maximum Columbia generation.

4. The Kelly Lake SVC is added in 2000 to increase the single-contingency var reserve on the Peace side of the Int-LM grid.

5. Circuit 5L83 is added in 2001 to increase the thermal and voltage stability limits on the Columbia side of the Int-LM grid.

6. The Malaspina SVC is added in 2003 to increase the single-contingency var reserve on the Peace side of the Int-LM grid.

7. The Nicola SVC is added in 2005 to increase the single-contingency var reserve on the Columbia side of the Int-LM grid.

8. Circuit 5L46 is added in 2007 to increase Peace system voltage stability limits.

Figure 5-4 in Appendix 5 shows how the voltage stability step increases provided by Sequence 2 keep pace with the growing Integrated System Probable peak load.

6.2.5 Line Losses

The Sequence 2 reduction in peak megawatt system loss, due to adding 5L46 and 5L83 to the existing 4-line system, is plotted in Figure 6-1; Appendix 6.

The change in system peak megawatt losses, due to the transmission and non-transmission additions, are shown on Page 4 of Table 7-6; Appendix 7.

7. ECONOMIC ANALYSIS

Tables 7-5 and 7-6 in Appendix 7 detail the derivation of the net present value (NPV) and cumulative present value (CPV) sequence costs in 1990 for the 1991-2040 cash flow period. The tables are organized as follows:

Page	Item
1	Direct cost (1990$) of each sequence addition.
2	Annual cost, including COH, taxes, operating and maintenance charges, of each addition on Page 1.
3	Present value (in 1990) of the annual costs on Page 2.
4	Present value of reduced losses due to additions.
5	Sequence NPV/CPV cost.
6	NPV/CPV cost for 5L46.
7	NPV/CPV cost for 5L83.
8	NPV/CPV cost for non-transmission additions.

The following are "basecase" assumptions:

- an 8% discount rate;
- a marginal value of Electricity which levels out in 2002 at 64 mills/kWh;
- zero non-firm exports;
- an Int-LM loss factor of 0.60.

Summary tables 7-3 and 7-4 in Appendix 7 show that, for these basecase assumptions:

a) The NPV cost of Sequence 2 is $9 million, or 13%, more than that of Sequence 1;

b) In Sequence 1, 5L46 pays back 86% of its capital and operating costs via reduced line losses over its economic lifetime.

8. SENSITIVITY STUDIES

This section discusses the results of studies done to determine the sensitivity of the above results to changes in the economic parameters.

8.1 Discount Rate

Figure 8-1 shows the sensitivity of the aggregate NPV cost of each sequence to a change in the discount rate. In summary, both NPV costs increase with increasing discount rate. Also, the lower the discount rate the greater the amount by which Sequence 2 NPV cost exceeds that of Sequence 1; both NPV costs are equal at 9% discount rate.

Circuit 5L46 pays back 100% of its capital and operating cost at approximately 7% discount rate.

8.2 Electricity Value

Figure 8-2 shows the sensitivity of the aggregate NPV cost of each sequence to a change in the long-term value of Electricity. In summary, both NPV costs reduce with increasing Electricity value. Also, the higher the Electricity value the greater the amount by which Sequence 2 NPV cost exceeds that of Sequence 1; both NPV costs are equal at approximately 42 mills/kWh.

8.3 Loss Factor

Figure 8-3 shows the sensitivity of the aggregate NPV cost of each sequence to a change in the Int-LM loss factor. In summary, both NPV costs reduce with increasing loss factor, i.e. with increasing transmission loss savings. Also, the higher the loss factor the greater the amount by which Sequence 2 NPV cost exceeds that of Sequence 1; both NPV costs are equal at approximately 0.50 loss factor.

8.4 5L46 Direct Cost

Figure 8-4 shows the sensitivity of the aggregate NPV cost of each sequence to a change in the 5L46 direct cost. A range of +/- 10% of Probable is shown. In summary, both NPV costs increase with increasing 5L46 direct cost. Also, the higher the 5L46 direct cost the lower the amount by which Sequence 2 NPV cost exceeds that of Sequence 1; both NPV costs are equal at approximately 118% of 5L46 Probable direct cost.

8.5 Indefinite Deferral of 5L46

Sequence 1 (5L46 in 1996) and Sequence 2 (5L46 in 2007) NPV costs for the basecase assumptions are approximately $69 million and $78 million, respectively. The NPV cost of a third sequence, derived by replacing 5L46 in Sequence 2 with three Nicola-sized SVC's, would be $97 million. Therefore, there is a net cost associated with continued deferment of 5L46[14], given its sizeable payback in reduced line losses, by replacing it with SVC's which actually increase system losses. Note that this result comes from studies which assumed no increase in Int-LM transfer after 2013. More likely, the Int-LM transfer will continue to rise after 2013 so that the NPV cost for indefinite deferral of 5L46 will be much higher than $97 million. Therefore, this sensitivity study concludes that 5L46 is an economic inevitability.

8.6 Downstream Power Benefits

Base case assumptions are that 1100 MW of DSB will be returned half at Ingledow and half at Selkirk. However, the potential range of DSB delivery over the peak load period is zero to 1400 MW and it could be returned at Ingledow, at Selkirk, and/or at a new substation near Oliver B.C. No detailed sensitivity studies were done to determine the effect on the sequence economics of changing either the amount or the location assumptions of the DSB deliveries. However, for the other parameters left unchanged:

1. Re-directing DSB delivery to Selkirk or Oliver will increase the Int-LM transfer and lower the Custer to Ingledow transfer. The net effect will be to increase system real power losses, increase both pre and post-outage var losses, and increase Int-LM thermal loadings. This would require earlier and larger Int-LM reinforcement, i.e. favouring the early transmission in Sequence 1. Conversely, re-directing DSB delivery to Ingledow will favour the deferred transmission in Sequence 2.

[14] $28 million or 40% over Sequence 1 NPV and $19 million or 24% over Sequence 2 (5L46 in 2007) NPV.

2. Reducing the size of the DSB delivery would likely require developing additional resources within BC. These replacement resources could come from both inside and outside the LM/VI load centre. Generally, replacement within the LM/VI load centre would yield a net increase in single-contingency dynamic var reserve because there would be no intermediate transmission involved. This would favour the deferred-transmission in Sequence 2. Alternatively, replacement resources developed outside the LM/VI load centre would reduce single-contingency dynamic var reserve because of the longer and more heavily loaded transmission lines that would be involved. This outcome would favour the early transmission in Sequence 1.

9. OTHER CONSIDERATIONS

1. Static Var Compensator reliability was discussed in [2]. BC Hydro's first operating experience with SVC's will begin with the Dunsmuir SVC in 1993. Sequence 1 will defer new SVCs until 1997 at which time four years of valuable operating experience would have been gained from this new technology.

2. Sequence 1 would be Resource Smart, i.e. the environmental impact of the transmission lines in this sequence would be offset by deferring the environmental impacts of additional hydro/thermal resources otherwise needed to make up increased Electricity losses.

3. Sequence 1 would increase planning flexibility because, after 5L46 and 5L83 have been installed, short lead-time SVC's and series capacitors can be easily advanced to meet short-notice situations such as higher than Probable load growth, sudden changes in the Resource Plan (e.g. due to low LM/VI IPP/DSM response), other than assumed DSB deliveries, etc.

   Over 80% of 5L46 expenditures will occur in the last three years of its construction period. Therefore, financial risks can be minimized by being prepared to defer the 5L46 completion date if load growth falls below Probable.

4. Prior to 2007, Sequence 1 provides more operating flexibility than does Sequence 2 because of the additional Int-LM second-contingency transfer capability that it provides[15]. Therefore, Sequence 1 can better accommodate system emergencies and uncertainties such as generation or transmission equipment outages, construction delays, higher than expected customer demand, etc.

5. At present, extensive use is being made of costly live line maintenance because of system reliability restrictions to taking major lines and equipment out of service. The early transmission in Sequence 1 will allow better maintenance outage scheduling and will facilitate the 5-10 year Maintenance Backlog Program whereby

[15] See [2] for a discussion of the relative second-contingency outage capabilities of 5L46 and non-transmission options.

ageing terminal equipment at all 500 kV substations is to be replaced.

6. Sequence 1 provides more non-firm transmission capability than does Sequence 2; this can be used to serve off-peak secondary energy exports.

7. Prior to 2007, Sequence 1 would provide more security of supply to Vancouver Island than would Sequence 2.

10. CONCLUSIONS

10.1 Technical

Both sequences satisfy System Transmission Planning Criteria specified in Section 3.

1. Powerflow

Prior to 2007, Sequence 1 provides more balance than does Sequence 2 in pre-outage power transfer amongst the Int-LM Peace lines. Sequence 2 requires 5L83 in 2001 to avoid single-contingency overloading at maximum Columbia generation.

2. Voltage Stability

Figures 5-1 and 5-2 in Appendix 5 showed the increases in system firm transmission capability provided by adding circuits 5L46 and 5L83. Regardless of which circuit is first, the greater increase occurs when the second circuit is added. This effect comes about because a new circuit is needed on both the Peace side and the Columbia sides of the Int-LM grid to realize an increase in Int-LM firm transmission capability matching the non-firm capability that a reinforcement to only one side provides. An analogy is that it is impossible to raise the level height of a table by increasing the length of the two legs that are on just one side; it has to be done on both sides. In effect, raising the second side gets all of the credit while raising the first side gets none. This is the case with the first circuit added in Figures 5-1 and 5-2. The analogy, however, is not exact because the first circuit does get some credit by virtue of its ability to raise the transfer capability on the opposite side of the Int-LM grid.

3. Transient Stability

Single-contingency transient stability was not explicitly tested in this study. However, the low pre- and post-outage GMS-ING and SEL-ING 500 kV bus voltage angles shown in sections 2 and 4 suggest that transient stability will not limit Int-LM transfer in either Sequence 1 or Sequence 2.

10.2 Economic

1. For basecase assumptions, the NPV cost in 1990 of Sequence 1 (early transmission) is $9 million less than that of Sequence 2 (deferred transmission).

2. A lower discount rate, a higher energy value, a higher loss factor, or a lower 5L46 direct cost improves the economics of Sequence 1 compared to Sequence 2. The difference in NPV cost of the two sequences is relatively insensitive to a change in the long term value of Electricity (equal at 42 mills/kWh) or the Int-LM loss factor (equal at 0.50). It is, however, sensitive to a change in the discount rate (equal at 9%), the 5L46 direct cost (equal at 118% of Probable) and to a large change in the DSB delivery assumptions.

3. Reduced peak load period DSB deliveries or re-direction of DSB deliveries towards Selkirk would increase Int-LM grid loading which would favour Sequence 1.

4. Circuit 5L46 (Sequence 1) pays back 86% of its capital and operating cost through reduced system losses. The payback is 100% at approximately 7% discount rate.

5. The NPV cost of Sequence 2 increases by $19 million when 5L46 is replaced in 2007 by three Nicola-sized SVC's[16], i.e. the indefinite deferral of 5L46. This result shows the economic inevitability of 5L46.

In summary, deferral of 5L46 is technically feasible but offers no economic advantages.

[16] Nicola SVC #2 in 2007, #3 in 2010, and #4 in 2012.

11. RECOMMENDATIONS

1. Build a second series compensated 500 kV line from Kelly Lake Substation to Cheekye Substation for service in 1996.

2. Determine the preferred system reinforcement for 1995.

3. Determine if an SVC or a 65% series compensated system is the best system reinforcement for 1997.

4. Carry out planning studies to determine the best reinforcement alternative for the eastern side of the Interior to Lower Mainland grid. Start environmental and route investigation studies for the Nicola to Meridian 500 kV transmission line (5L83).

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1. CAPABILITY OF THE INTERIOR TO LOWER MAINLAND TRANSMISSION SYSTEM, B.C. HYDRO SYSTEM TRANSMISSION PLANNING REPORT NO. SP9009, MARCH 1991.

2. INTERIOR TO LOWER MAINLAND TRANSMISSION REINFORCEMENT OPTIONS, B.C. HYDRO SYSTEM TRANSMISSION PLANNING REPORT NO. SP9010, MARCH 1991.

3. KELLY LAKE TO CHEEKYE SECOND 500 KV TRANSMISSION LINE PROJECT JUSTIFICATION, B.C. HYDRO SYSTEM TRANSMISSION PLANNING REPORT NO. SP9012, MARCH 1991.

4. EVALUATION OF ALTERNATE REINFORCEMENT PLANS - IDENTIFICATION OF ALTERNATIVE TECHNOLOGIES TO KELLY LAKE-CHEEKYE #2 500 kV LINE, POWERTECH LABS INC, SYSTEMS ANALYSIS AND CONTROL PROJECT NO. 2251-20, MARCH,1991.

5. REPORT ON THERMAL CAPABILITY STUDIES OF THE TWO SEQUENCES, NOTE TO FILE 1440-450A, 7 DECEMBER 1990.

6. CRITERIA FOR AC TRANSMISSION SYSTEM PERFORMANCE, NATIONAL POWER SURVEY, PART II, FEDERAL POWER COMMISSION ADVISORY COMMITTEE, REPORT NO. 6, U.S. GOVERNMENT PRINTING OFFICE, 1964.

APPENDIX 1

POWERFLOW ASSUMPTIONS

POWERFLOW ASSUMPTIONS

TABLES

1-1 CASE P8700: LOAD-RESOURCE BALANCE AND BASIC ASSUMPTIONS

1-2 CASE P10700: LOAD-RESOURCE BALANCE AND BASIC ASSUMPTIONS

1-3 CASE P13200: LOAD-RESOURCE BALANCE AND BASIC ASSUMPTIONS

TABLE 1-1

SYSTEM PLANNING VOLTAGE STABILITY STUDIES

CASE P8700

LOAD-RESOURCE BALANCE & BASIC ASSUMPTIONS

AREA INTERCHANGE

	MW(+OUT, -IN)
NET WITH NORTHWEST	120
NET WITH TAUC	0
NET WITH WKP	229
NET WITH ALCAN	-675
TOTAL AREA INTERCHANGE	-326
HVDC LEVEL (ALL CABLES IN SERVICE)	654 MW

LOADS AND RESOURCES	MW (MVAR) MAX PEACE	BALANCED PCE/COL	MAX COL
LOADS (HW PEAK LOAD)			
BCH P	8116	8116	8116
Q	(3018)	(3018)	(3018)
LOSSES (BCH)	633	605	589
BCH LOAD + LOSSES	8749	8721	8705
INTERCHANGE (BCH)	-322	-326	-325
TOTAL GENERATION (BCH)	8427	8395	8380
WKP P	831	831	831
Q	(239)	(239)	(239)

Oct. 11/1990

TABLE 1-1

GENERATION SCHEDULE

PLANT	MW MAX PEACE	MW BALANCE PCE/COL	MW MAX COL
*BRIDGE	328	328	328
*CMS	70	70	70
GMS	2730	2304	1696
KCL	219	292	529
*LM EQUIV	329	329	329
MICA	1413	1544	1740
PCANYON	700	700	568
REVEL	1496	1636	1844
7-MILE	492	537	606
*VI EQUIV	411	411	411
WGS	47	51	58
C.I. IPP	160	160	160
OTHER	32	33	41
	8427	8395	8380

*SUMS TO 1138 MW ALL CASES; KEMANO APPROXIMATELY 1400 (MAX) MW ALL CASES

OTHER NOTABLE ASSUMPTIONS

1. APPROX. 1994/95 SYSTEM REPRESENTATION INCLUDING 5L13 AND DMR SVC (PRE 5L46 AND 5L83)

2. PLANTS OUTSIDE LM/VI REPRESENTED ON A UNIT BASIS

3. NO EQUIVALENCING INSIDE BCH/WKP

4. BPA EQUIVALENT DEVELOPED FROM WSCC CASE 1988 HW4

5. HELWAY PHASE SHIFTER HOLDS 50 MW BCH/BPA COUNTER CLOCKWISE LOOP FLOW

6. NO LINE DROP COMPENSATION EXCEPT AT BURRARD (4 SYNCS ON 60% LDC TO 230 KV BUS)

7. SWITCHED SHUNT CAPACITORS ADDED TO MAJOR LOAD CENTRE SUBSTATIONS AS REQUIRED TO MAINTAIN NOMINAL PRE-DISTURBANCE VOLTAGES AND DYNAMIC VAR RESERVE.

8. SWITCHED SHUNT CAPACITORS ADDED TO DISTRIBUTION SUBSTATION BUSES SUCH THAT NO PRE-DISTURBANCE BUS VOLTAGE LESS THAN .98 PU.

Mar. 26/1990

TABLE 1-2

SYSTEM PLANNING VOLTAGE STABILITY STUDIES

CASE P10700

LOAD-RESOURCE BALANCE & BASIC ASSUMPTIONS

AREA INTERCHANGE

	MW(+OUT, -IN)
NET WITH NORTHWEST (SCL=120; DSB=-1100)	-980
NET WITH TAUC	0
NET WITH WKP	330
NET WITH ALCAN	-697
TOTAL AREA INTERCHANGE	-1347
HVDC LEVEL (138 KV CABLES OUT OF SERVICE)	654 MW

LOADS AND RESOURCES	MW (MVAR) MAX PEACE	BALANCED PCE/COL	MAX COL
LOADS (HW PEAK LOAD)			
BCH P	10055	10055	10055
Q	(3473)	(3473)	(3473)
LOSSES (BCH)	746	655	655
BCH LOAD + LOSSES	10801	10710	10711
INTERCHANGE (BCH)	-1347	-1347	-1347
TOTAL GENERATION (BCH)	9454	9363	9363
WKP P	1039	1039	1039
Q	(325)	(325)	(325)

Mar. 7/1991

TABLE 1-2

GENERATION SCHEDULE

PLANT	MW MAX PEACE	MW BALANCE PCE/COL	MW MAX COL
*BRIDGE	328	328	328
*CMS	70	70	70
GMS	2730	2305	1148
KCL	502	264	529
*LM EQUIV	329	329	329
MICA	870	1395	1740
PCANYON	700	498	468
SITE C	900	569	402
REVEL	922	1479	1844
7-MILE (INCL. SEV 4)	404	648	808
LCD (N/INCL. SEV 4)	1035	830	1035
*VI EQUIV	411	411	411
WGS	58	47	58
C.I. IPP	160	160	160
OTHER	35	30	33
	9454	9363	9363

*SUMS TO 1138 MW ALL CASES; KEMANO 1420 (MAX) MW ALL CASES

1. APPROX. 2003/04 SYSTEM REPRESENTATION INCLUDING 5L13, DMR SVC, 5L46, AND 5L83.

2. LOWER COLUMBIA DEVELOPMENT (LCD) INCLUDES BRX 225 MW, WAX 570 MW, AND KLS 240 MW CAPABILITIES.

3. PLANTS OUTSIDE LM/VI REPRESENTED ON A UNIT BASIS.

4. NO EQUIVALENCING INSIDE BCH/WKP.

5. BPA EQUIVALENT DEVELOPED FROM WSCC CASE 1988 HW4.

6. NELWAY PHASE SHIFTER HOLDS 50 MW BCH/BPA COUNTER CLOCKWISE LOOP FLOW.

7. NO LINE DROP COMPENSATION EXCEPT AT BURRARD (4 SYNCS ON 60% LDC TO 230 KV BUS).

8. SWITCHED SHUNT CAPACITORS ADDED TO MAJOR LOAD CENTRE SUBSTATIONS AS REQUIRED TO MAINTAIN NOMINAL PRE-DISTURBANCE VOLTAGES AND DYNAMIC VAR RESERVE. SWITCHED SHUNT CAPACITORS ADDED TO DISTRIBUTION SUBSTATION BUSES SUCH THAT NO PRE-DISTURBANCE VOLTAGE IS LESS THAN 1.00.

9. LONG RADIALS EXTRACTED.

Mar. 7/1991

TABLE 1-3

SYSTEM PLANNING VOLTAGE STABILITY STUDIES

CASE P13200

LOAD-RESOURCE BALANCE & BASIC ASSUMPTIONS

AREA INTERCHANGE

	MW(+OUT, -IN)
NET WITH NORTHWEST (SCL=120; DSB=-1100)	-980
NET WITH TAUC	0
NET WITH WKP	454
NET WITH ALCAN	-697
TOTAL AREA INTERCHANGE	-1223
HVDC LEVEL (138 KV CABLES OUT OF SERVICE)	654 MW

LOADS AND RESOURCES	MW (MVAR) MAX PEACE	MAX COL
LOADS (MW PEAK LOAD)		
BCH P	12207	12207
Q	(4099)	(4099)
LOSSES (BCH)	965	944
BCH LOAD + LOSSES	13172	13151
INTERCHANGE (BCH)	-1224	-1224
TOTAL GENERATION (BCH)	11948	11927
WKP P	1039	1039
Q	(325)	(325)

Mar. 7/1991

TABLE 1-3
GENERATION SCHEDULE

PLANT	MW MAX PEACE	MW MAX COL
*BRIDGE	328	328
*CMS	70	70
GMS	2730	2444
KCL	329	529
*LM EQUIV	329	329
MICA	1740	1740
PCANYON	700	700
SITE C	900	300
REVEL	1382	1844
7-MILE (INCL. SEV 4)	606	808
LCD (N/INCL. SEV 4)	1610	1610
*VI EQUIV	411	411
WGS	58	58
LOWER CANYON	360	360
*ELAHO	204	204
C.I. IPP	160	160
OTHER	31	32
	11948	11927

*SUMS TO 1342 MW ALL CASES; KEMANO 1420 (MAX) MW ALL CASES

1. APPROX. 2017/18 SYSTEM REPRESENTATION INCLUDING 5L13, DMR SVC, 5L46, 5L83. ASSUMES ZERO NET VANCOUVER ISLAND LOAD GROWTH AFTER 2002.
2. LOWER COLUMBIA DEVELOPMENT (LCD) INCLUDES BRX 225 MW, WAX 570 MW, KLS 240 MW, MPY 300 MW, AND BDR 275 MW CAPABILITIES.
3. PLANTS OUTSIDE LM/VI REPRESENTED ON A UNIT BASIS.
4. NO EQUIVALENCING INSIDE BCH/WKP.
5. BPA EQUIVALENT DEVELOPED FROM WSCC CASE 1988 HW4.
6. NELWAY PHASE SHIFTER HOLDS 50 MW BCH/BPA COUNTER CLOCKWISE LOOP FLOW.
7. NO LINE DROP COMPENSATION EXCEPT AT BURRARD (4 SYNCS ON 60% LDC TO 230 KV BUS).
8. SWITCHED SHUNT CAPACITORS ADDED TO MAJOR LOAD CENTRE SUBSTATIONS AS REQUIRED TO MAINTAIN NOMINAL PRE-DISTURBANCE VOLTAGES AND DYNAMIC VAR RESERVE. SWITCHED SHUNT CAPACITORS ADDED TO DISTRIBUTION SUBSTATION BUSES SUCH THAT NO PRE-DISTURBANCE VOLTAGE IS LESS THAN 1.02.
9. LONG RADIALS EXTRACTED.

Mar. 7/1991

APPENDIX 2

PRE-OUTAGE POWERFLOWS

PRE-OUTAGE POWERFLOWS (MW)

FIGURES

2-1	CASE P8700P:	1994/95 MAXIMUM PEACE GENERATION	(4 LINES)
2-2	CASE P8700C:	1994/95 MAXIMUM COLUMBIA GENERATION	(4 LINES)
2-3	CASE P10700P:	2003/04 MAXIMUM PEACE GENERATION	(6 LINES)
2-4	CASE P10700C:	2003/04 MAXIMUM COLUMBIA GENERATION	(6 LINES)
2-5	CASE P13200P:	2017/18 MAXIMUM PEACE GENERATION	(6 LINES)
2-6	CASE P13200C:	2017/18 MAXIMUM COLUMBIA GENERATION	(6 LINES)
2-7	CASE P10700P:	2003/04 MAXIMUM PEACE GENERATION	(5 LINES)
2-8	CASE P10700C:	2003/04 MAXIMUM COLUMBIA GENERATION	(5 LINES)
2-9	CASE P13200P:	2017/18 MAXIMUM PEACE GENERATION	(5 LINES)
2-10	CASE P13200C:	2017/18 MAXIMUM COLUMBIA GENERATION	(5 LINES)

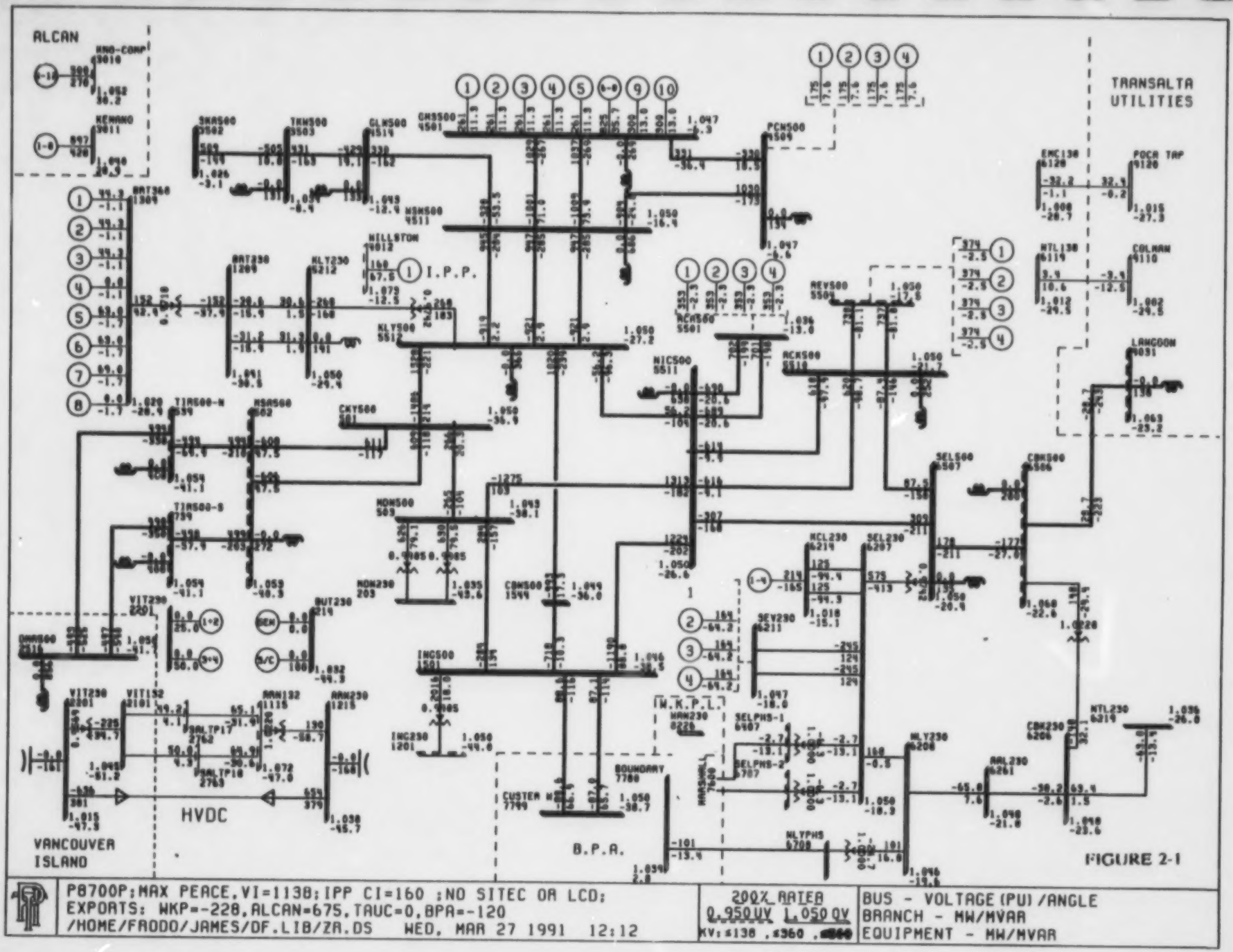

ALCAN
TRANSALTA UTILITIES
I.P.P.
HVDC
VANCOUVER ISLAND
B.P.A.
W.K.P.L.
P8700P;MAX PEACE,VI=1138;IPP CI=160 ;NO SITEC OR LCD;
EXPORTS: WKP=-228,ALCAN=675,TAUC=0,BPA=-120
/HOME/FADDO/JAMES/DF.LIB/ZA.DS WED, MAR 27 1991 12:12
200% RATED
0.950 UV 1.050 OV
BUS - VOLTAGE (PU) /ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

FIGURE 2-1

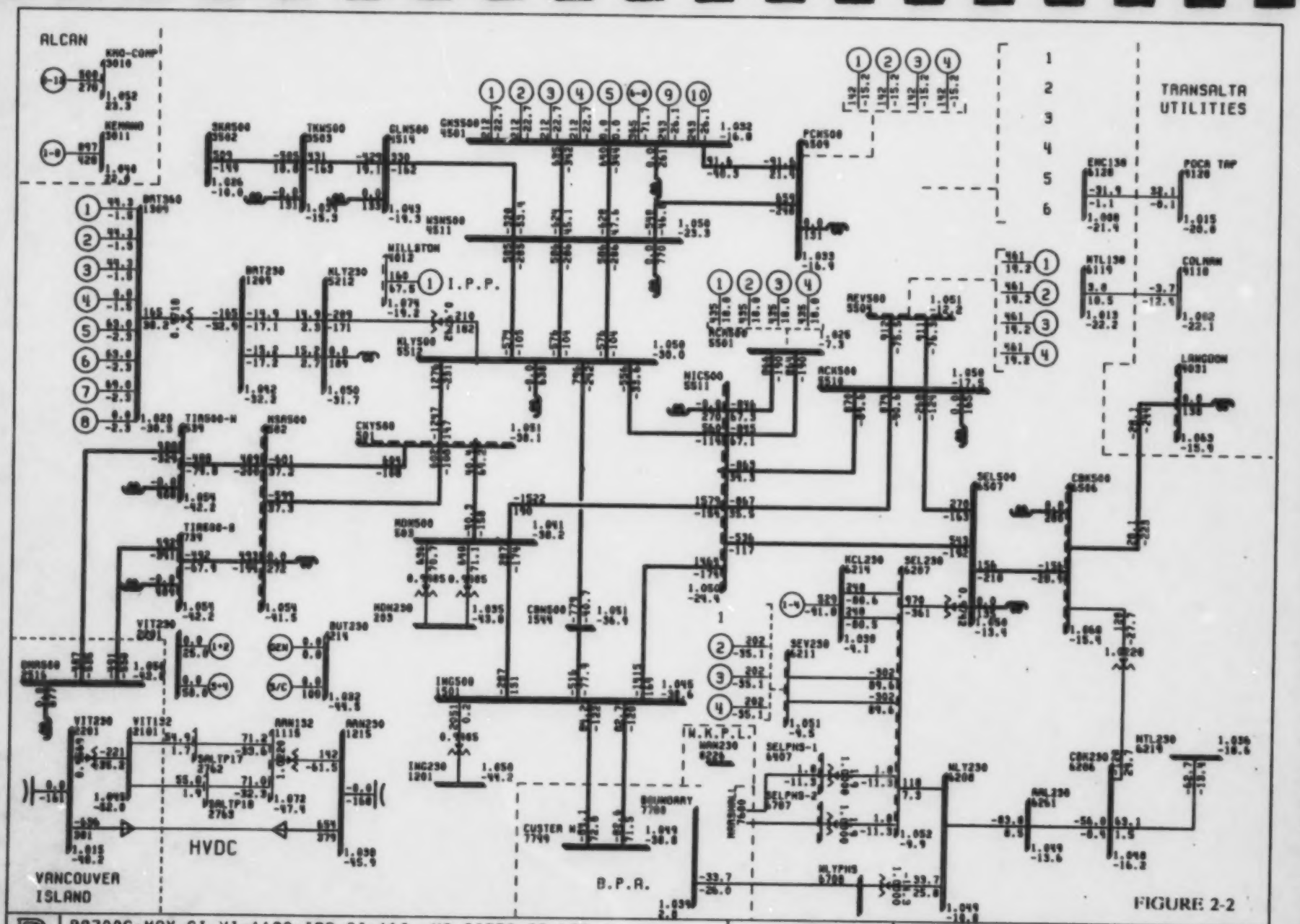

ALCAN
TRANSALTA UTILITIES
I.P.P.
HVDC
VANCOUVER ISLAND
B.P.A.
W.K.P.L.
P8700C;MAX CI,VI=1138;IPP CI=160 ;NO SITEC OR LCD;
EXPORTS: WKP=-220,ALCAN=675,TAUC=0,BPA=-120
/HOME/FRODO/JAMES/DF.LIB/ZR.DS WED, MAR 27 1991 12:38
200% AREA
0.950UV 1.050 OV
KV: ≤138 . ≤360 . ≤800
BUS - VOLTAGE (PU) /ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

FIGURE 2-2

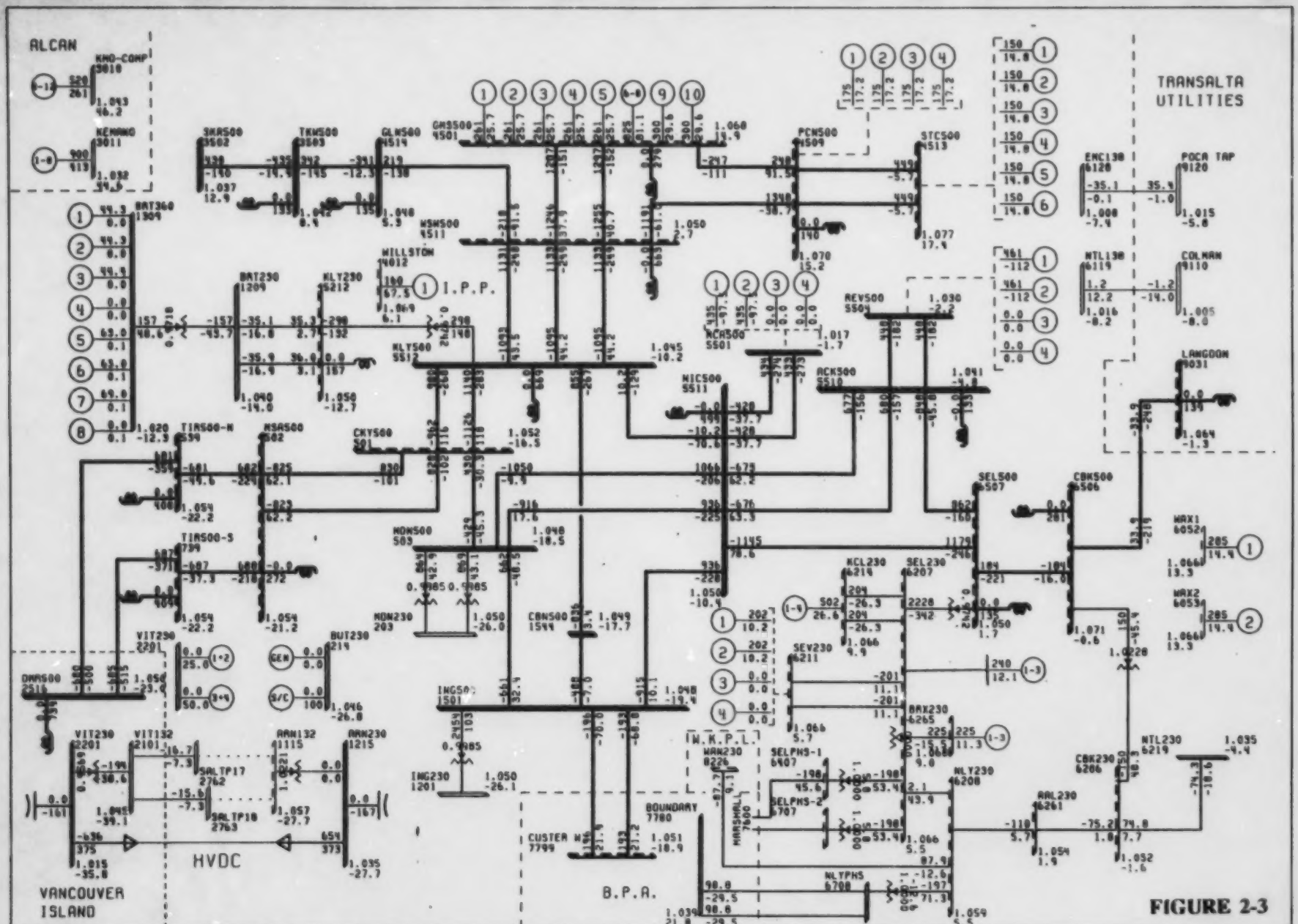

ALCAN
KMO-COMP
KEMANO
TRANSALTA
UTILITIES
I.P.P.
WILLSTON
HVDC
VANCOUVER
ISLAND
B.P.A.
W.K.P.L.
MARSHALL
BOUNDARY
CUSTER
P10700P6L:MAX PC GEN;DMR SVC,SL13,46,83, (6 LM LINES)
STC,AS,IPPS;EXPORTS: WKP=-330,ALCAN=697,TAUC=0,BPA=-960(DSB)
/HOME/FRODO/JAMES/DF.LIB/ZR.DS MON, MAR 04 1991 19:18
200% RATED
0.950 UV 1.050 OV
KV: ≤138 .≤360 .≤500
BUS - VOLTAGE (PU) /ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

FIGURE 2-3

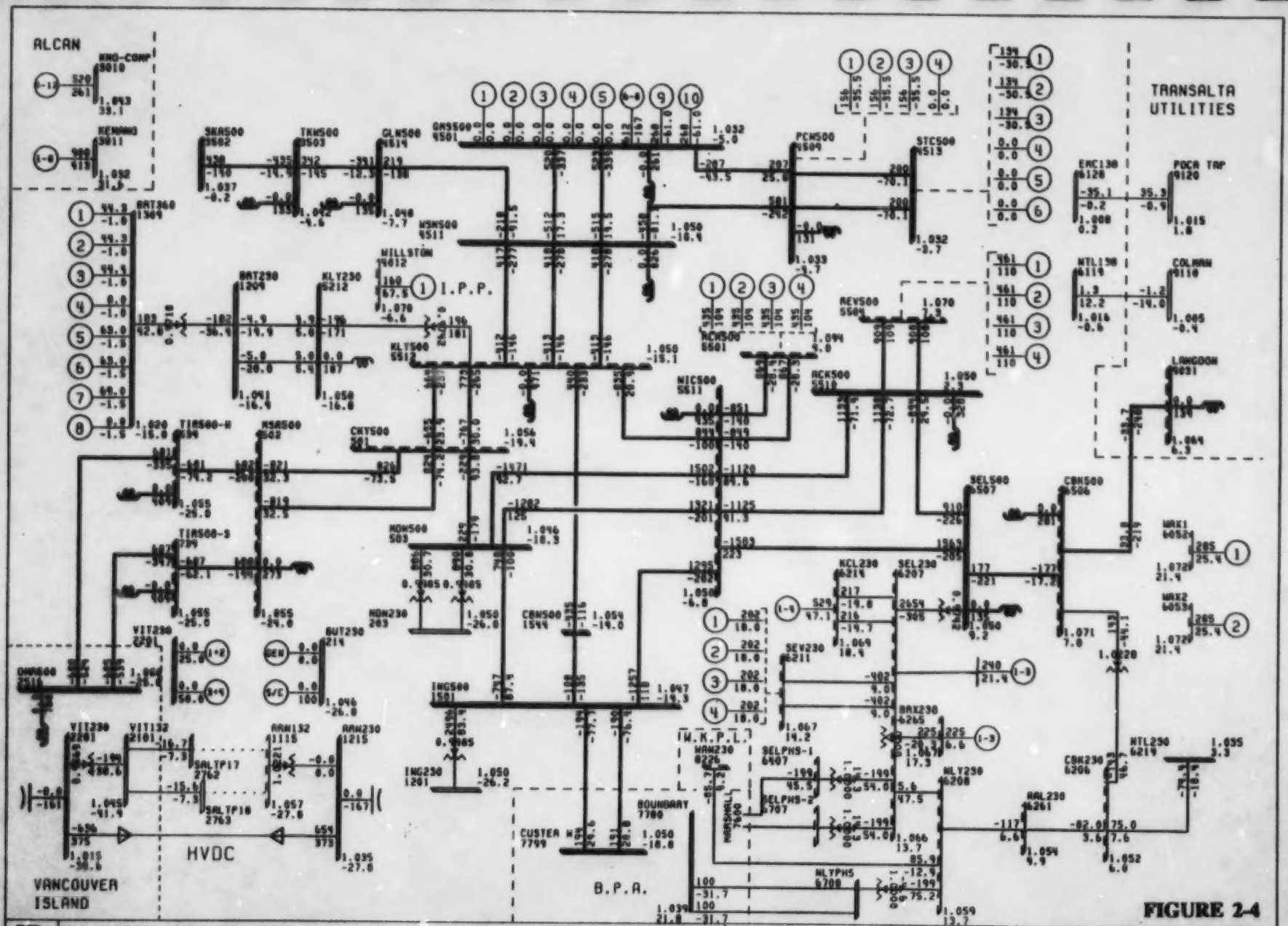
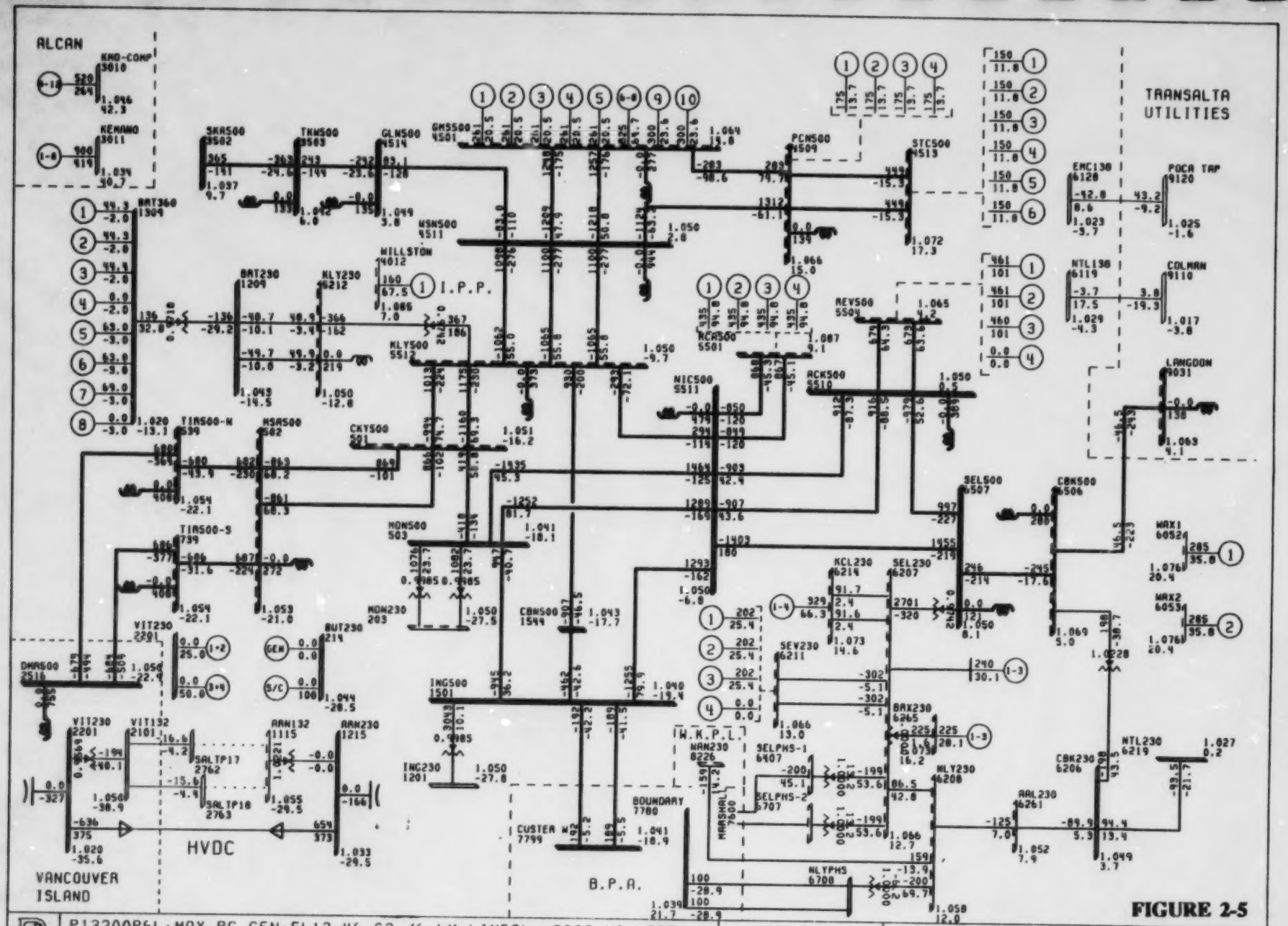

ALCAN
TRANSALTA UTILITIES
I.P.P.
HVDC
VANCOUVER ISLAND
B.P.A.
W.K.P.L.
P10700C6L:MAX COL GEN;DMA SVC,5L13,46,83, (6 LM LINES)
STC,AS,IPPS;EXPORTS: WKP=-330,ALCAN=697,TAUC=0,BPA=-980(DSB)
/HOME/FRODO/JAMES/DF.LIB/ZA.DS MON, MAR 04 1991 18:53
200% RATED
0.950UV 1.050 OV
KV: ≤138 , ≤360 , ≤500
BUS - VOLTAGE(PU)/ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

FIGURE 2-4



P13200P6L:MAX PC GEN;SL13,46,83 (6 LM LINES), 2003 VI LOAD
STC,LCD,ELA,LCN,IPPS;WKP=-454,ALCAN=697,TAUC=0,BPA=-980(DSB)
/HOME/FRODO/JAMES/DF.LIB/ZR.DS MON, MAR 04 1991 18:54

200% RATED
0.950 UV 1.050 OV
KV: ≤138 , ≤360 , ≤500

BUS - VOLTAGE (PU) /ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

FIGURE 2-5

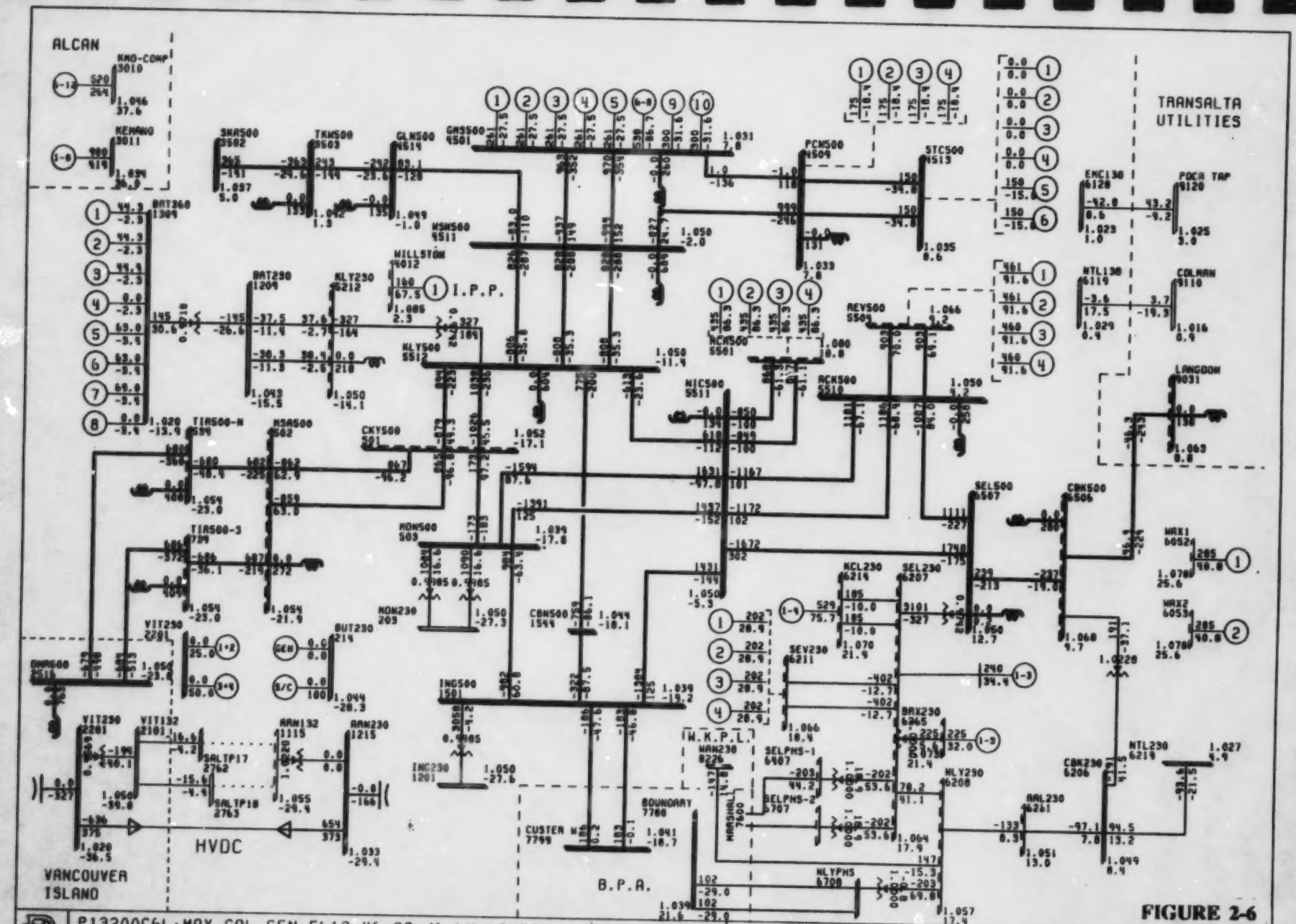


FIGURE 2-6

P13200C6L:MAX COL GEN;5L13,46,83 (6 LM LINES), 2003 VI LOAD
STC,LCD,ELA,LCN,IPPS;WKP=-454,ALCAN=697,TAUC=0,BPA=-980(DSB)
/HOME/FRODO/JAMES/DF.LIB/ZR.DS MON. MAR 04 1991 18:55

200% RATER
0.950 UV 1.050 OV
KV: ≤138 , ≤360 , ≤500

BUS - VOLTAGE (PU) /ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

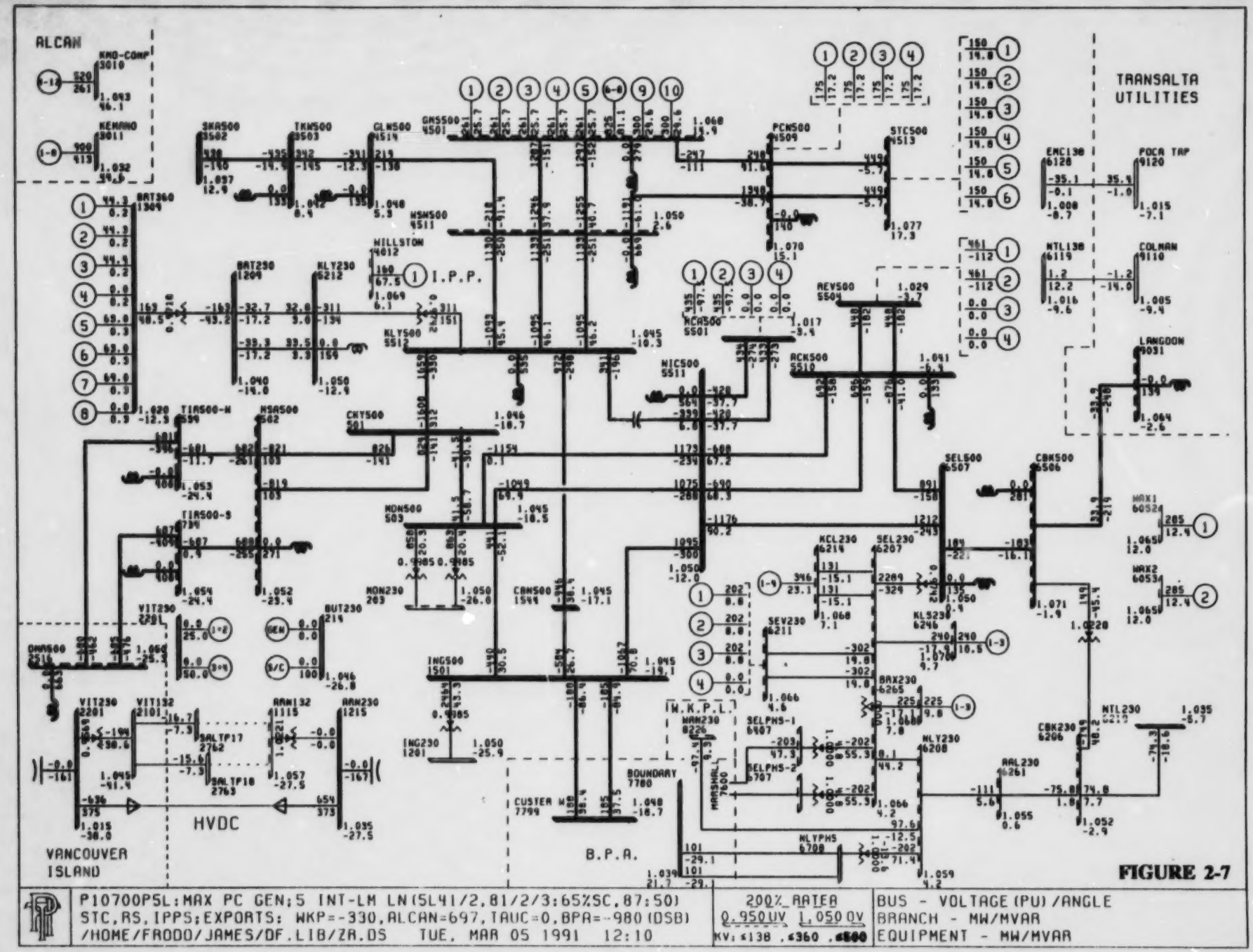
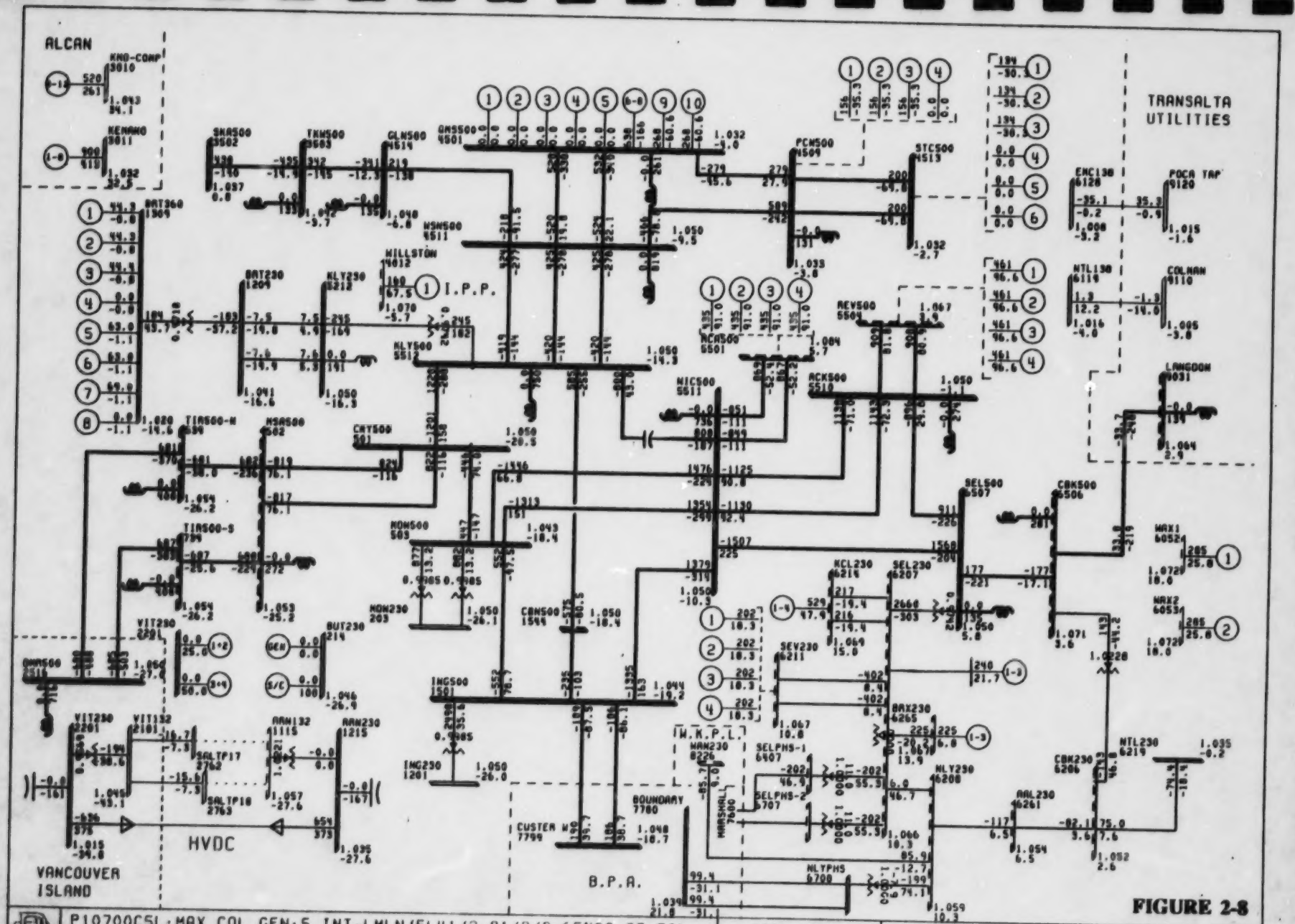

ALCAN
TRANSALTA UTILITIES
I.P.P.
HVDC
VANCOUVER ISLAND
B.P.A.
W.K.P.L.
P10700PSL:MAX PC GEN;5 INT-LM LN(SL41/2,81/2/3:65%SC,87:50)
STC,RS,IPPS;EXPORTS: WKP=-330,ALCAN=697,TAUC=0,BPA=-980(DSB)
/HOME/FRODO/JAMES/DF.LIB/ZR.DS TUE. MAR 05 1991 12:10
200% RATER
0.950UV 1.050OV
KV: ≤138 ,≤360 ,≤500
BUS - VOLTAGE(PU)/ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

FIGURE 2-7



P10700CSL;MAX COL GEN;5 INT-LMLN(5L41/2,81/2/3:65%SC,87:50)
STC,RS,IPPS;EXPORTS: WKP=-330,ALCAN=697,TAUC=0,BPA=-980(DSB)
/HOME/FRODO/JAMES/DF.LIB/ZR.DS MON, MAR 04 1991 19:31

200% RATED
0.950 UV 1.050 OV
KV: ≤138 , ≤360 , ≤500

BUS - VOLTAGE (PU) /ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

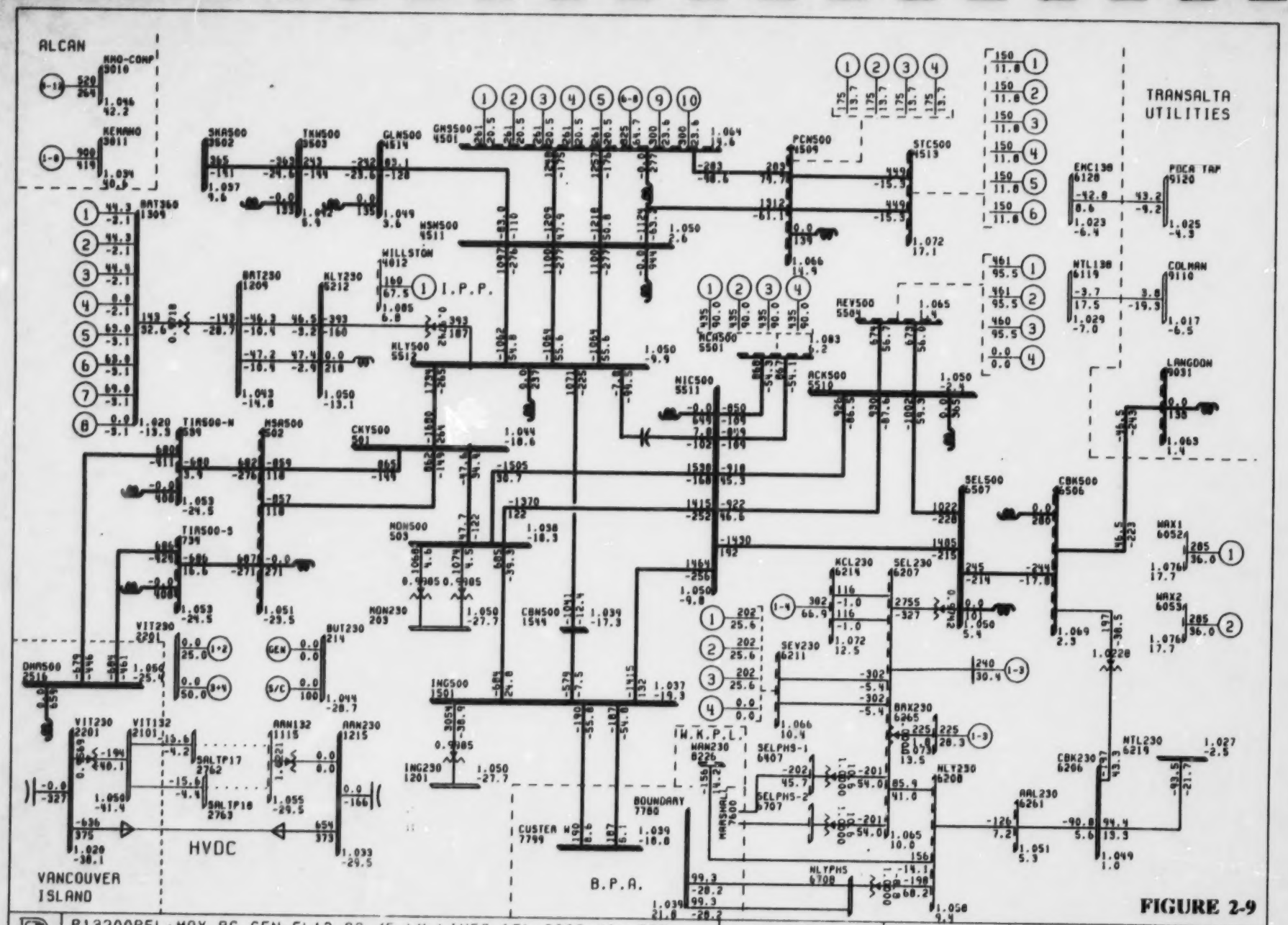

ALCAN
KMO-COMP
KEMANO
TRANSALTA
UTILITIES
I.P.P.
HVDC
VANCOUVER
ISLAND
B.P.A.
W.K.P.L.
P13200PSL:MAX PC GEN;SL13,83 (5 LM LINES,65),2003 VI LOAD
STC,LCD,ELA,LCN,IPPS;WKP=-454,ALCAN=697,TAUC=0,BPA=-980 (CSB)
/HOME/FRODO/JAMES/DF.LIB/ZR.DS MON, MAR 04 1991 19:36
200% RATED
0.950 UV 1.050 OV
KV: ≤138 , ≤360 , ≤500
BUS - VOLTAGE (PU) /ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

FIGURE 2-9

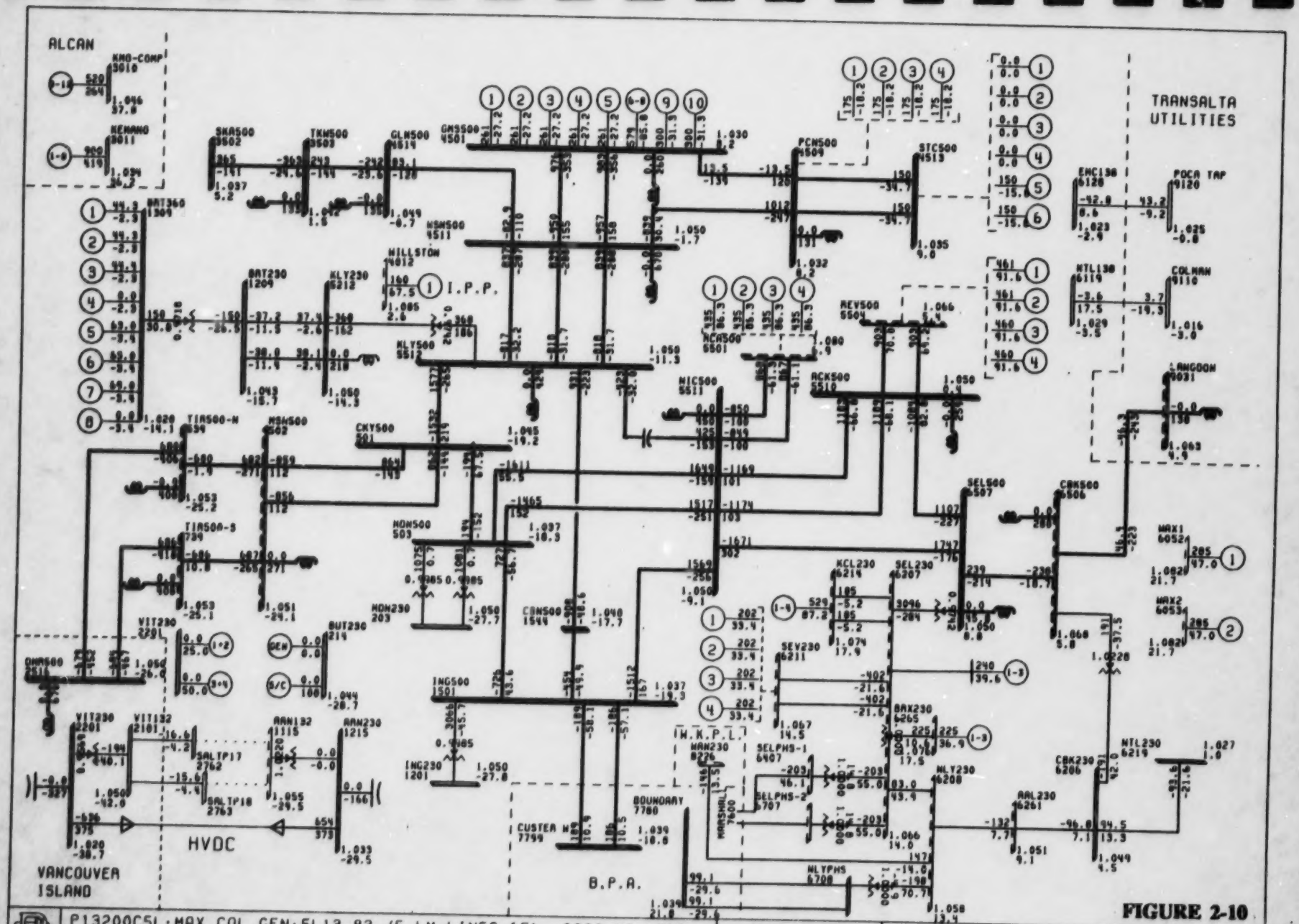

ALCAN
TRANSALTA UTILITIES
I.P.P.
HVDC
VANCOUVER ISLAND
B.P.A.
W.K.P.L.
P13200C5L;MAX COL GEN;5L13,83 (5 LM LINES,65), 2003 VI LOAD
STC,LCD,ELA,LCN,IPPS;WKP=-454,ALCAN=697,TAUC=0,BPA=-980(DSB)
/HOME/FRODO/JAMES/DF.LIB/ZR.DS MON, MAR 04 1991 19:44
200% RATER
0.950 UV 1.050 OV
KV: 6138 .6360 .6586
BUS - VOLTAGE (PU) /ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

FIGURE 2-10

APPENDIX 3

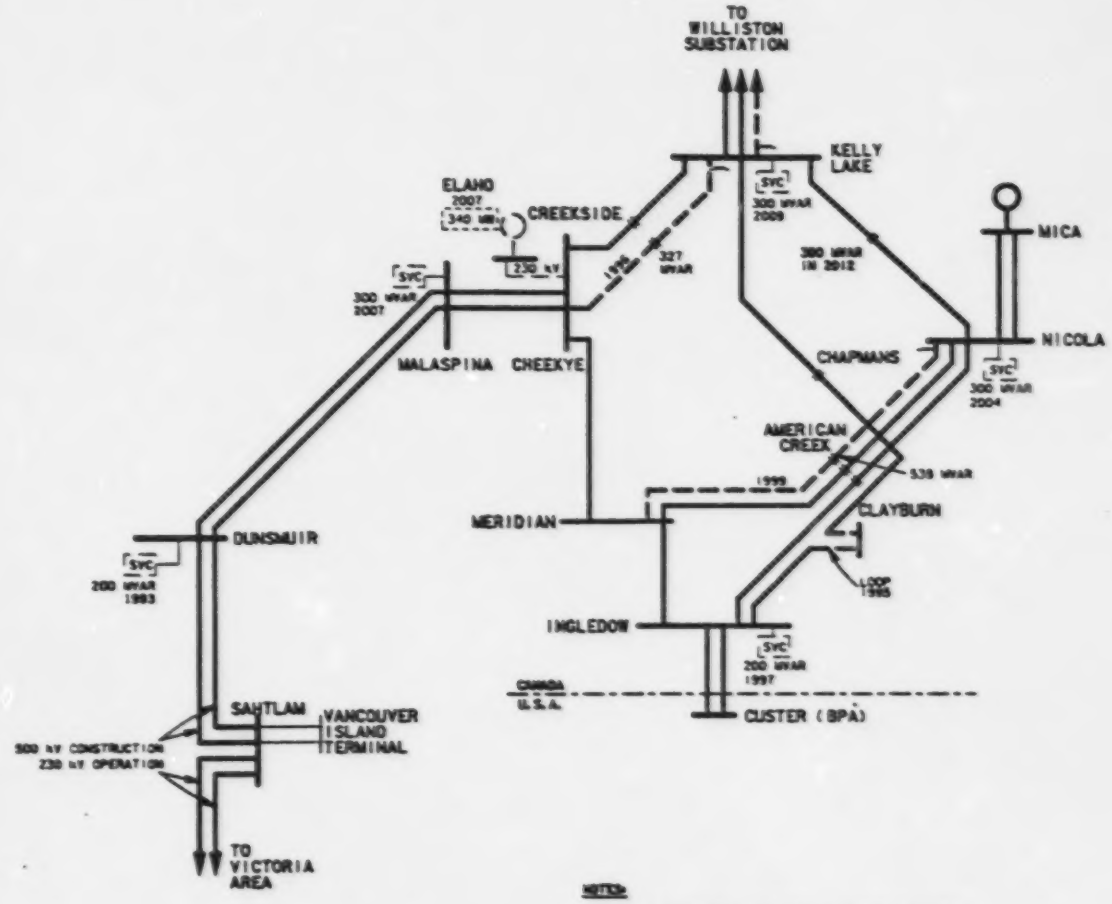
DEVELOPMENT SEQUENCES

DEVELOPMENT SEQUENCES

FIGURES

3-1 SEQUENCE 1: TRANSMISSION BEGINNING IN 1996 WITH 5L46

3-2 SEQUENCE 2: DEFERRED TRANSMISSION ALTERNATIVE



NOTES:

1. VOLTAGE STABILITY STUDIES DO NOT ACCOUNT FOR GENERATION ADDITIONS SCHEDULED AFTER 2005.
2. ASSUMES ALL STATIC VAR COMPENSATORS (SVC) CONNECTED TO 230 kV BUS.
3. YEARS CORRESPOND TO 1st YEAR OF FISCAL YEARS (1 APR TO 31 MAR OF FOLLOWING YEAR).
4. SVC RATINGS ARE CAPACITIVE ONLY.
5. VANCOUVER ISLAND NET LOAD GROWTH AFTER 2002 ASSUMED TO BE TO BE ZERO (MET BY LOCAL GENERATION OR BY LOAD MANAGEMENT ON V. I.).
6. INCREASE FROM 50% TO 60% SERIES COMPENSATION AT CHAPMANS, CREEKSIDE, AND AMERICAN CREEK IN 2011.
7. 50% SERIES COMPENSATION ON NICOLA - KELLY LAKE (SL67) IN 2012.

ASSUMED RESOURCE PLAN

RESOURCES	PROBABLE	RESOURCES	PROBABLE
KEMANEYSINE	1998	MURPHY CREEK	2008
WAKETA EXP.	2002	ELAND	2007
JOHN HOLE 4	2003	[illegible]	2013
BRILLIANT EXP.	2005		
PEACE SITE C	2005		
BOCAN	2006		
LOWER COMPOX	2006		

NOTE: FOR THIS PLAN IT HAS BEEN ASSUMED THAT DOWNSTREAM BENEFITS WILL BE RETURNED 50% AT HAMLEDON AND 50% AT SELKIRK.

TOTAL TO B.C.H.: 1998/99 - 100 MW
1999/00 - 500 MW
2003/04 - 1100 MW

KEY

- EXISTING 500 kV DBW TRANSMISSION
- PLANNED 500 kV DBW TRANSMISSION
- EXISTING 230 kV MW TRANSMISSION
- PLANNED 230 kV MW TRANSMISSION

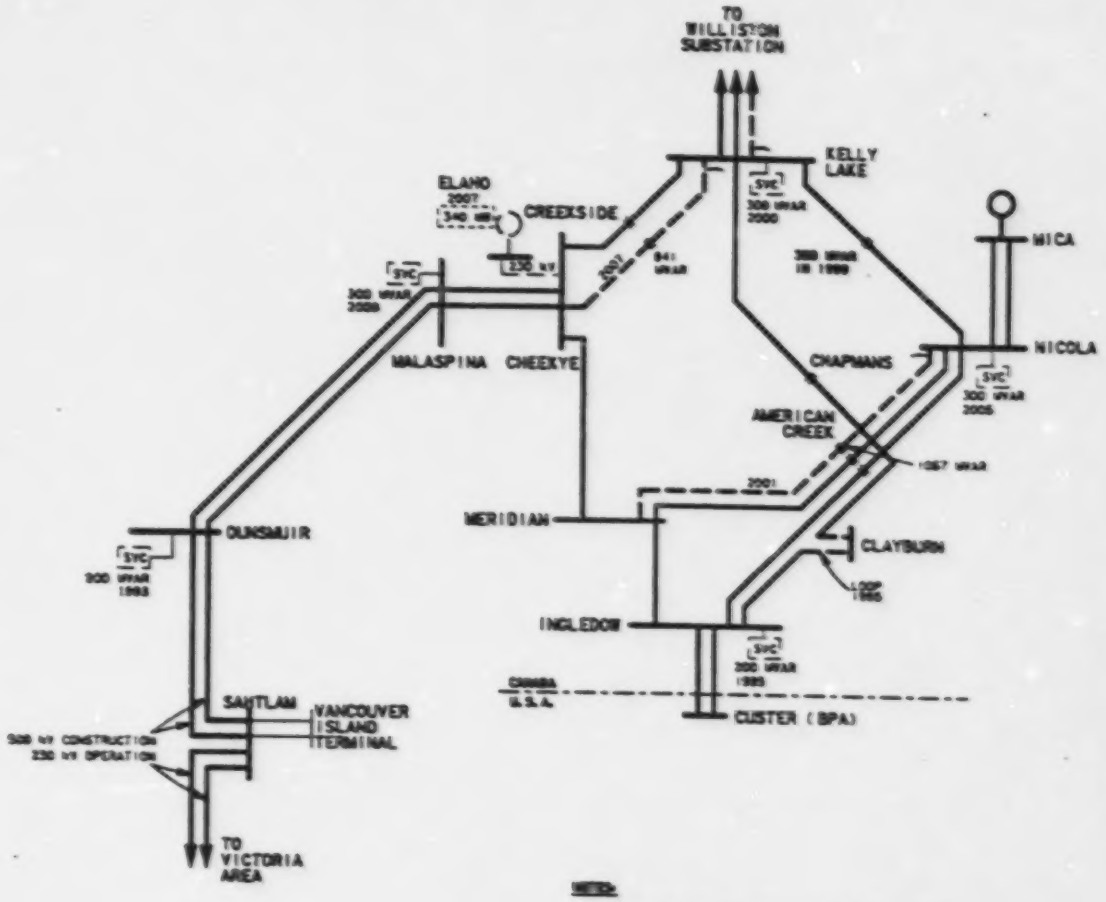
FIGURE 3-1

BCHydro ☐ System Planning Division

INTERIOR TO LOWER MAINLAND
500 KV TRANSMISSION
SEQUENCE 1
TRANSMISSION BEGINNING IN 1996 WITH SL46

DWG No. CJ5.DGN SHT. 1

C.A. - 14 FEB 91



NOTES:

1. VOLTAGE STABILITY STUDIES DO NOT ACCOUNT FOR GENERATION ADDITIONS SCHEDULED AFTER 2006.
2. ASSUMES ALL STATIC VAR COMPENSATORS (SVC) CONNECTED TO 230 kV BUS.
3. YEARS CORRESPOND TO 1st YEAR OF FISCAL YEARS (1 APR TO 31 MAR OF FOLLOWING YEAR).
4. SVC RATINGS ARE CAPACITIVE ONLY.
5. VANCOUVER ISLAND NET LOAD GROWTH AFTER 2002 ASSUMED TO BE TO BE ZERO (NET OF LOCAL GENERATION OR BY LOAD MANAGEMENT OR T. L.).
6. INCREASE FROM 500 TO 600 SERIES COMPENSATION AT CHAPMANS, CREEKSIDE, AND AMERICAN CREEK IN 1997.
7. 500 SERIES COMPENSATION ON NICOLA - KELLY LAKE (LAST) IN 1998.

ASSUMED RESOURCE PLAN

RESOURCES	PROBABLE	RESOURCES	PROBABLE
KEEMLEYSIDE	1998	MURPHY CREEK	2006
TAHETA EXP.	2002	ELAND	2007
REFEX MILE 4	2003	BANNER	2013
BRILLIANT EXP.	2005		
PEACE SITE C	2005		
DUNCAN	2005		
LOWER CAMPBELL	2006		

NOTE: FOR THIS PLAN IT WAS BEEN ASSUMED THAT [illegible] WILL BE RETURNED SVC AT INGLEDOW AND SVC AT DELKIRK.

TOTAL TO U.S.A.: 1998/99 - 100 MW
1999/00 - 600 MW
2003/04 - 1100 MW

KEY

- EXISTING 500 kV DBV TRANSMISSION
- PLANNED 500 kV SVC TRANSMISSION
- EXISTING 230 kV DBV TRANSMISSION
- PLANNED 230 kV DBV TRANSMISSION

FIGURE 3-2

Hydro System Planning Division
INTERIOR TO LOWER MAINLAND 500 KV TRANSMISSION SEQUENCE 2 DEFERRED TRANSMISSION ALTERNATIVE
DWG No. CJS. DGN SHT. 2

G.A. - 14 FEB 91

APPENDIX 4

OUTAGE POWERFLOWS (CURRENT)

OUTAGE POWERFLOWS (AMPERES)

TABLES

4-1 SUMMARY OF SINGLE-CONTINGENCY OUTAGE CURRENTS FOR SEQUENCE 1

4-2 SUMMARY OF SINGLE-CONTINGENCY OUTAGE CURRENTS FOR SEQUENCE 2

FIGURES

4-1 CASE P10700P: MAXIMUM PEACE, 6 LINES - LOSS OF 5L42

4-2 CASE P10700C: MAXIMUM COLUMBIA, 6 LINES - LOSS OF 5L82

4-3 CASE P9550C: MAXIMUM COLUMBIA, 4 LINES - LOSS OF 5L81

4-4 CASE P10000C: MAXIMUM COLUMBIA, 4 LINES - LOSS OF 5L81

4-5 CASE P11800P: MAXIMUM PEACE, 5 LINES - LOSS OF 5L41

4-6 CASE P13200P: MAXIMUM PEACE, 5 LINES - LOSS OF 5L41

4-7 CASE P13200C: MAXIMUM COLUMBIA, 5 LINES - LOSS OF 5L82

TABLE 4-1

Sequence 1 (6-line systems)

Case	Year	BCH Load (MW)	Gen. Pattern	Outage	Max. Post-Outage I (A)	Max. Post-Outage I Circuit	Ref. Fig.
1	2003	10700	max P	5L42	1985	5L46	4-1
2	2003	10700	max C	5L82	2311	5L83	4-2

Notes:

1. System adjusted.
2. Cases 1 and 2 include 5L46 and 5L83.
3. Existing series compensation.
4. Circuits 5L46 and 5L83 "Delta" type structures and 4 x 927 mcm ACSR conductor bundles.
5. No current loading above 3000 ampere limit.

TABLE 4-2

Sequence 2

Case	Year	BCH Load (MW)	Gen. Pattern	Outage	Max. Post-Outage I (A)	Circuit	Ref. Fig.
1	1998	9550	max C	5L81	3038	5L82	4-3
2	2000	10000	max C	5L81	2939	5L82	4-4
3	2009	11800	max P	5L41	2470	5L42	4-5
4	2017	13200	max P	5L41	2366	5L42	4-6
5	2017	13200	max C	5L82	2565	5L83	4-7

Notes:

1. System adjusted.

2. Cases 1 and 2 are the 4-line (existing) Int-LM system, cases 3, 4 and 5 are 5-line Int-LM systems.

3. Case 1 is existing 4-line system and 5L82 flow over 3000 amperes is thermal justification for 5L87 series compensation in 1999 and 5L83 in 2001.

4. 65% series compensation on 5L41, 5L42, 5L81, 5L82 and 5L83.

5. 50% series compensation on 5L87 in cases 2, 3, 4, and 5.

6. Circuits 5L46 and 5L83 "Delta" type structures and 4 x 927 mcm ACSR conductor bundles.

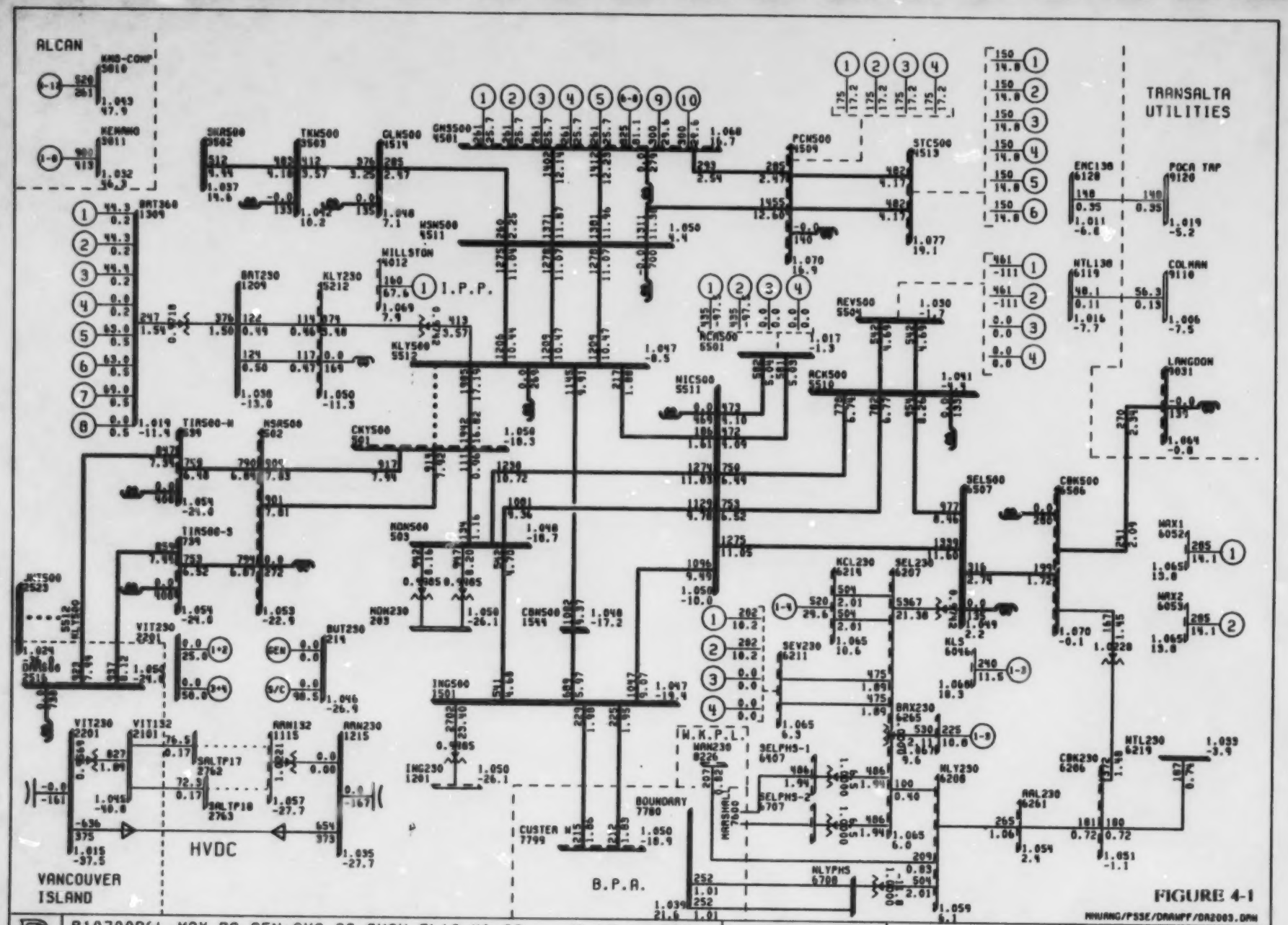

ALCAN
TRANSALTA UTILITIES
I.P.P.
HVDC
VANCOUVER ISLAND
W.K.P.L.
B.P.A.
P10700P6L:MAX PC GEN;SVC AS SWSH;5L13,46,83 (6 LM LN,50%)
STC,AS,IPP; EXPORTS: WKP=-330;ALCAN=697;TAUC=0;BPA=980(DSB)
5L42 OUT-OF-SERVICE MON, DEC 03 1990 11:20
200% RATED
0.950UV 1.050OV
KV: ≤138 .≤360 .≤500
BUS - VOLTAGE(PU)/ANGLE
BRANCH - AMPS/PU CURRENT
EQUIPMENT - MW/MVAR

FIGURE 4-1

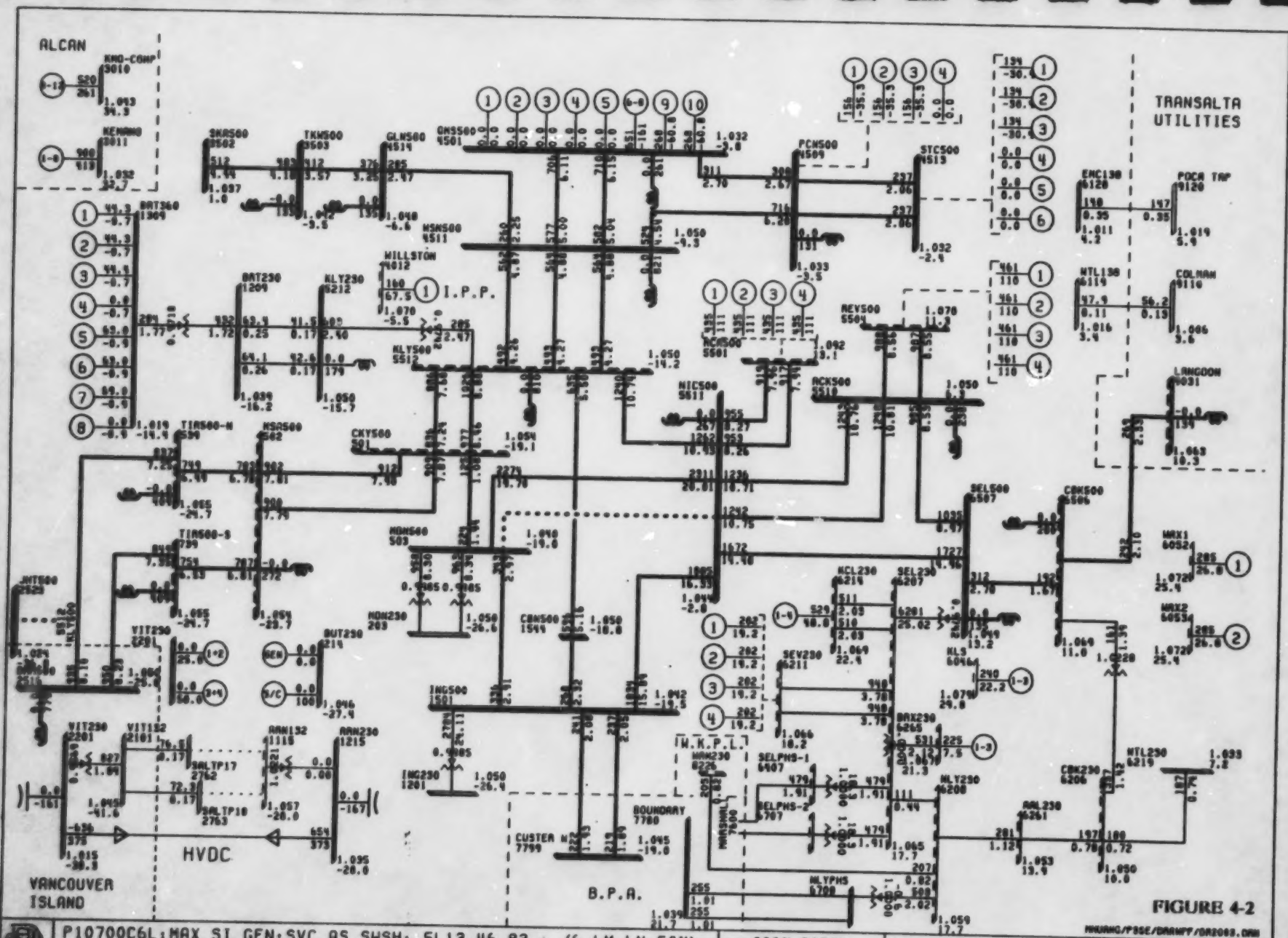

ALCAN
TRANSALTA UTILITIES
I.P.P.
HVDC
VANCOUVER ISLAND
B.P.A.
W.K.P.L.
P10700C6L:MAX SI GEN;SVC AS SWSH; SL13,46,83 ; (6 LM LN,50%)
STC,AS,IPP; EXPORTS: WKP=-330,ALCAN=697,TAUC=0,BPA=980 (DSB)
5L82 OUT-OF-SERVICE MON, DEC 03 1990 11:26
200% RATEA
0.950UV 1.050 OV
KV: ≤138 , ≤360 , ≤500
BUS - VOLTAGE (PU) /ANGLE
BRANCH - AMPS/PU CURRENT
EQUIPMENT - MW/MVAR

FIGURE 4-2

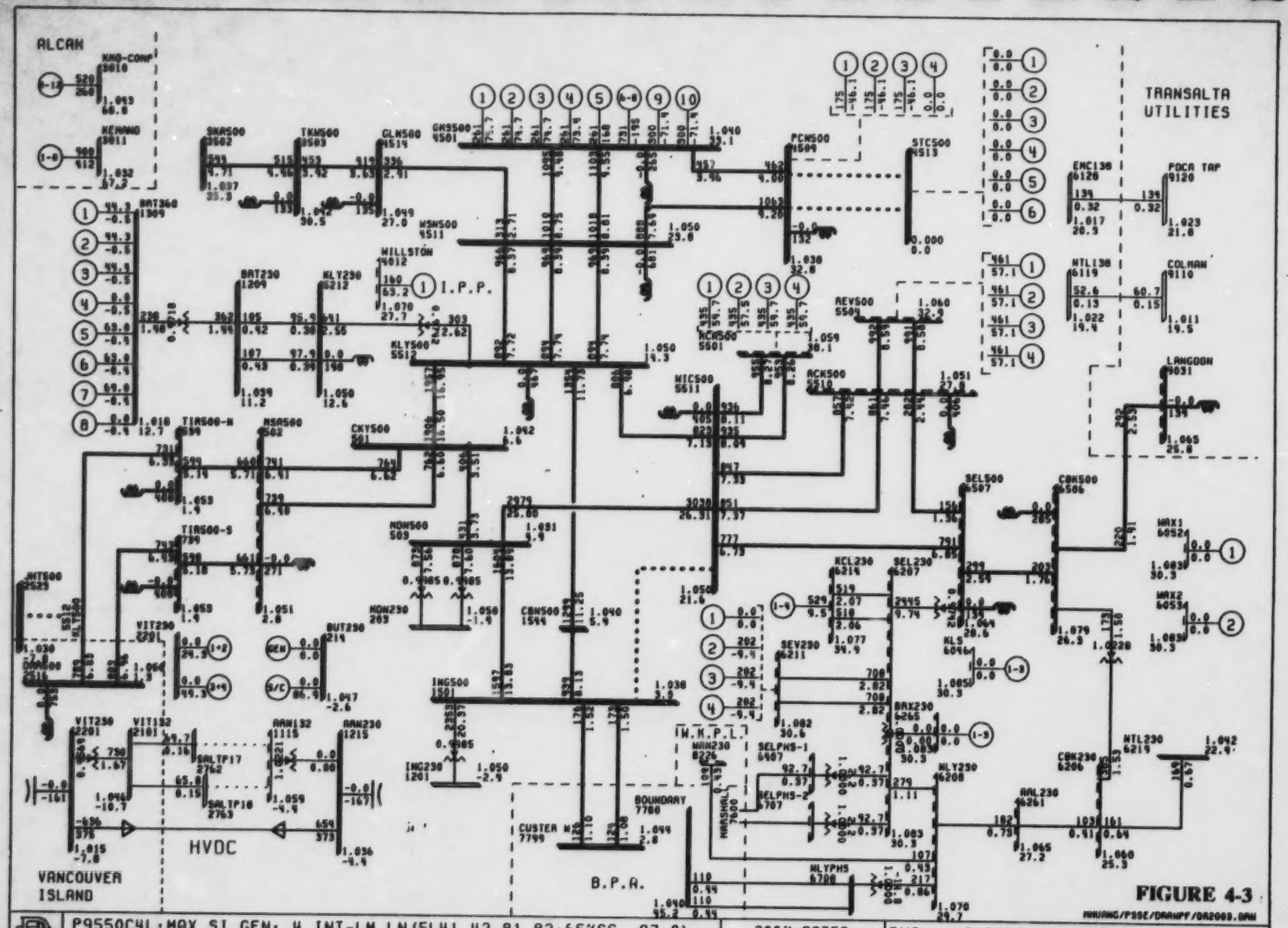


FIGURE 4-3

MHUANG/PSSE/DRAWPF/DR2003.DRW

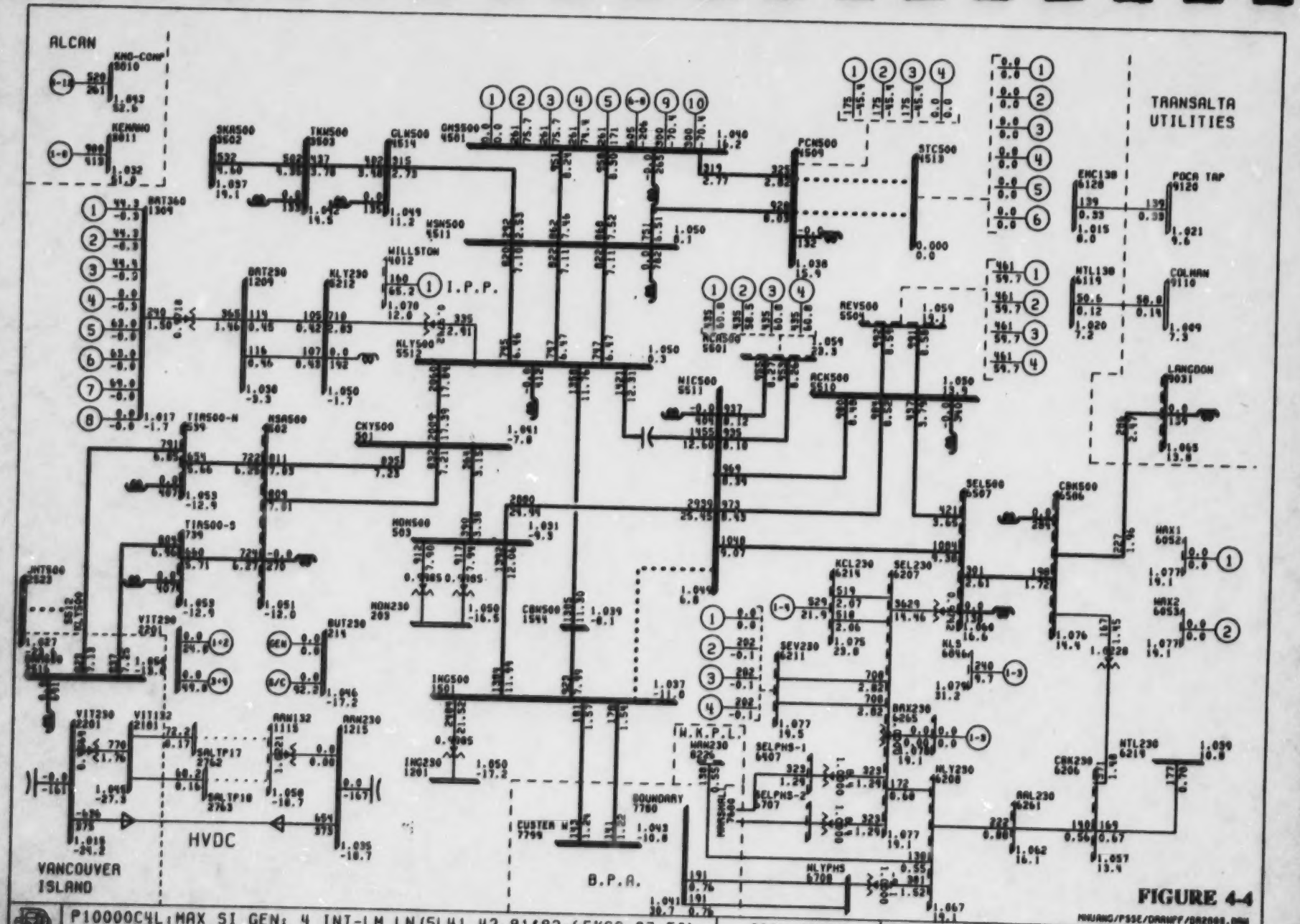


FIGURE 4-4

MAVANG/PSSE/DRAWFF/BR2000.DWG

P10000C4L:MAX SI GEN; 4 INT-LM LN(5L41,42,81&82:65%SC,87:50)
KLS:240MW; EXPORTS:WKP=-297,ALCAN=697,TAUC=0,BPA=605(725DSB)
5L81 OUT-OF-SERVICE TUE, DEC 04 1990 11:43

200% RATED
0.950 UV 1.050 OV
KV: ≤138 , ≤360 , ≤500

BUS - VOLTAGE (PU) /ANGLE
BRANCH - AMPS/PU CURRENT
EQUIPMENT - MW/MVAR

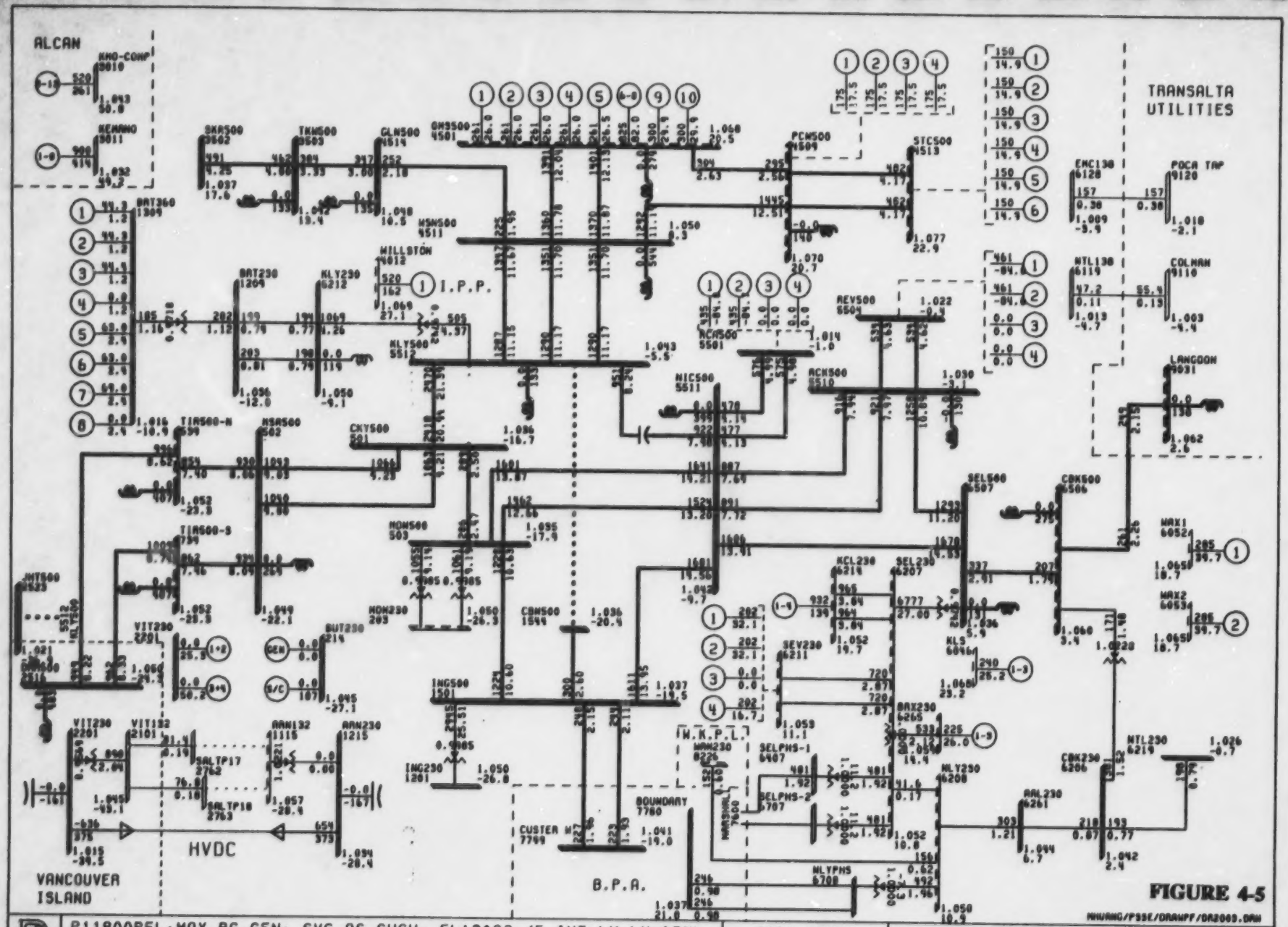


FIGURE 4-5

MHURNG/PSSE/DRAWPF/DR2003.DRW

P11800P5L:MAX PC GEN; SVC AS SWSH; SL13&83 (5 INT-LM LN,65%)
STC,LCD,IPP,LCN; EXPORTS:WKP=-330,ALCAN=697,TAUC=0,BPA=980
SL41 OUT-OF-SERVICE TUE, DEC 04 1990 13:40

200% RATED
0.950 UV 1.050 OV
KV: ≤138 , ≤360 , ≤500

BUS - VOLTAGE (PU) /ANGLE
BRANCH - AMPS/PU CURRENT
EQUIPMENT - MW/MVAR

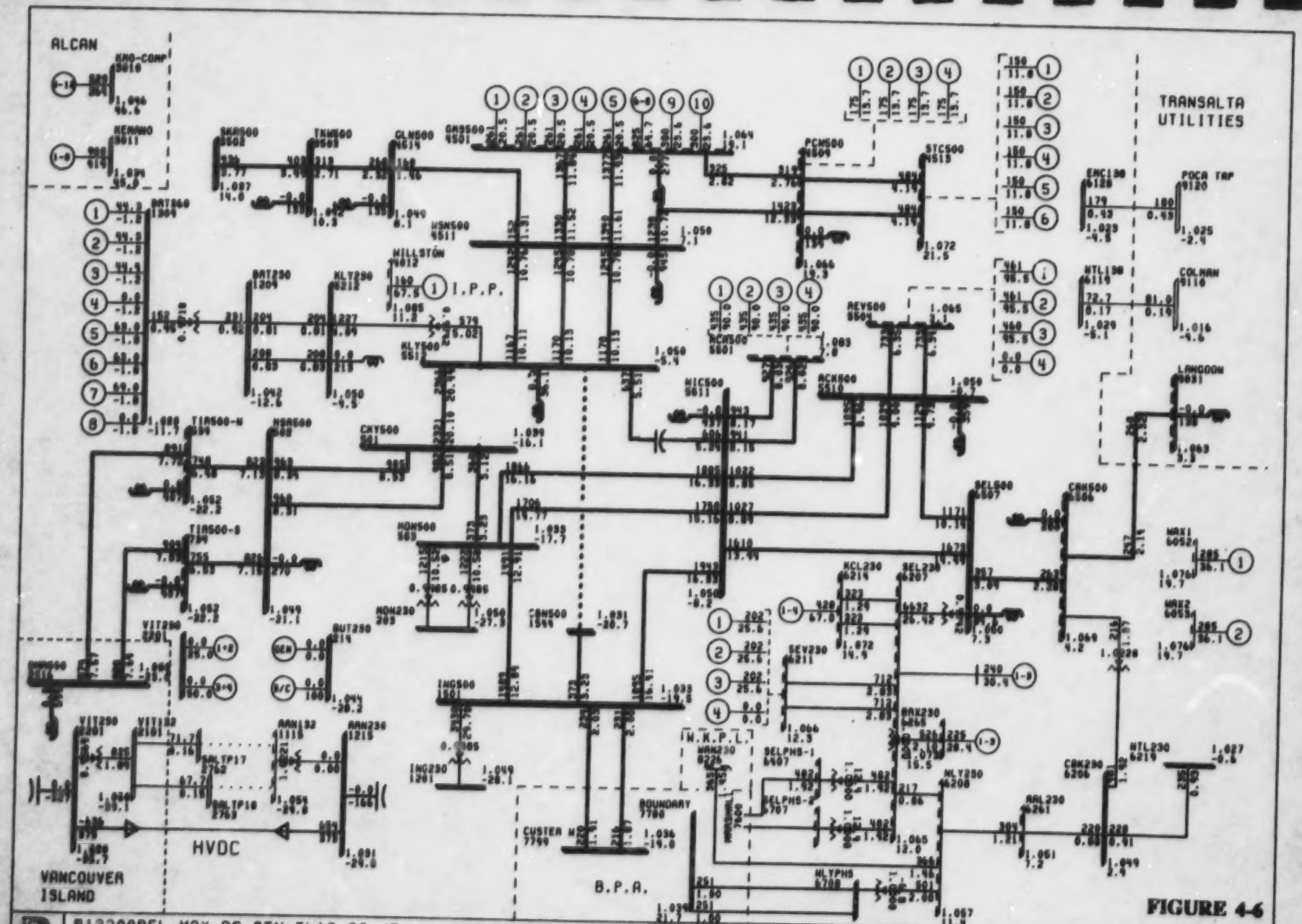

ALCAN
KAO-COMP
KEMANO
TRANSALTA UTILITIES
I.P.P.
HVDC
VANCOUVER ISLAND
B.P.A.
W.K.P.L.
P13200P5L:MAX PC GEN;5L13,83 (5 LN LINES), 2003 VI LOAD
STC,LCD,ELA,LCN,IPPS;WKP=-454,ALCAN=697,TAUC=0,BPA=-980 (DSB)
5L41 OUT-OF-SERVICE THU, MAR 07 1991 12:27
200% RATED
0.950 UV 1.050 OV
KV: ≤138 , ≤360 , ≤500
BUS - VOLTAGE (PU) /ANGLE
BRANCH - AMPS/PU CURRENT
EQUIPMENT - MW/MVAR

FIGURE 4-6

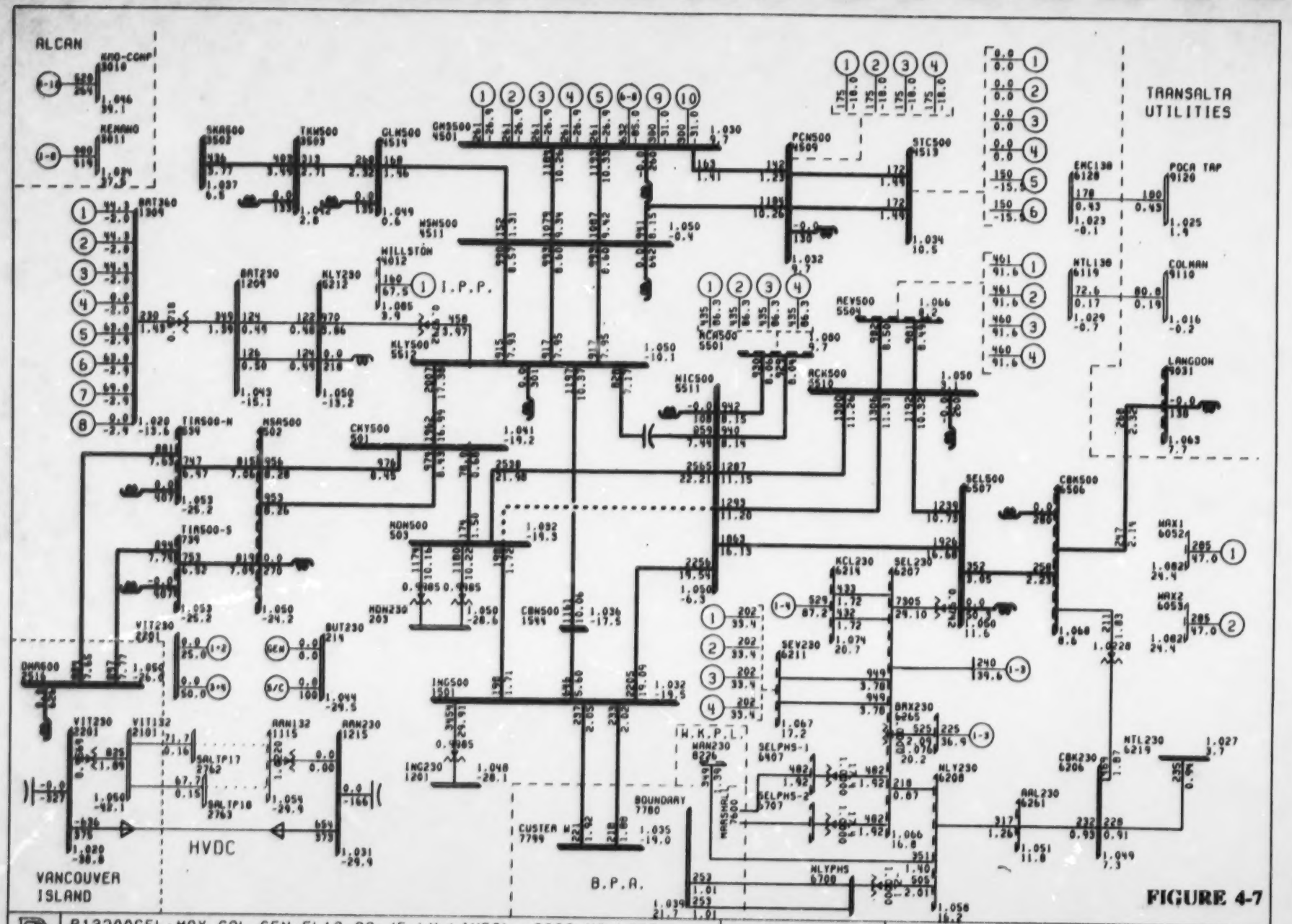

ALCAN
TRANSALTA UTILITIES
I.P.P.
W.K.P.L.
B.P.A.
HVDC
VANCOUVER ISLAND
P13200C5L:MAX COL GEN;SL13,83 (5 LM LINES), 2003 VI LOAD
STC,LCD,ELA,LCN,IPPS;WKP=-454,ALCAN=697,TAUC=0,BPA=-980 (DSB)
SL82 OUT-OF-SERVICE THU, MAR 07 1991 12:33
200% RATED
0.950 UV 1.050 OV
KV: ≤138 , ≤360 , ≤500
BUS - VOLTAGE (PU) /ANGLE
BRANCH - AMPS/PU CURRENT
EQUIPMENT - MW/MVAR

FIGURE 4-7

APPENDIX 5

VOLTAGE STABILITY RESULTS

VOLTAGE STABILITY RESULTS

FIGURES

5-1 SEQUENCE 1 STAGING AND SINGLE-CONTINGENCY DYNAMIC VAR RESERVE

5-2 SEQUENCE 2 STAGING AND SINGLE-CONTINGENCY DYNAMIC VAR RESERVE

5-3 SEQUENCE 1 FIRM TRANSMISSION LOAD CARRYING CAPABILITY

5-4 SEQUENCE 2 FIRM TRANSMISSION LOAD CARRYING CAPABILITY

INTERIOR TO LOWER MAINLAND TRANSMISSION REINFORCEMENT
SEQUENCE 1
STAGING AND SINGLE - CONTINGENCY
DYNAMIC VAR RESERVE

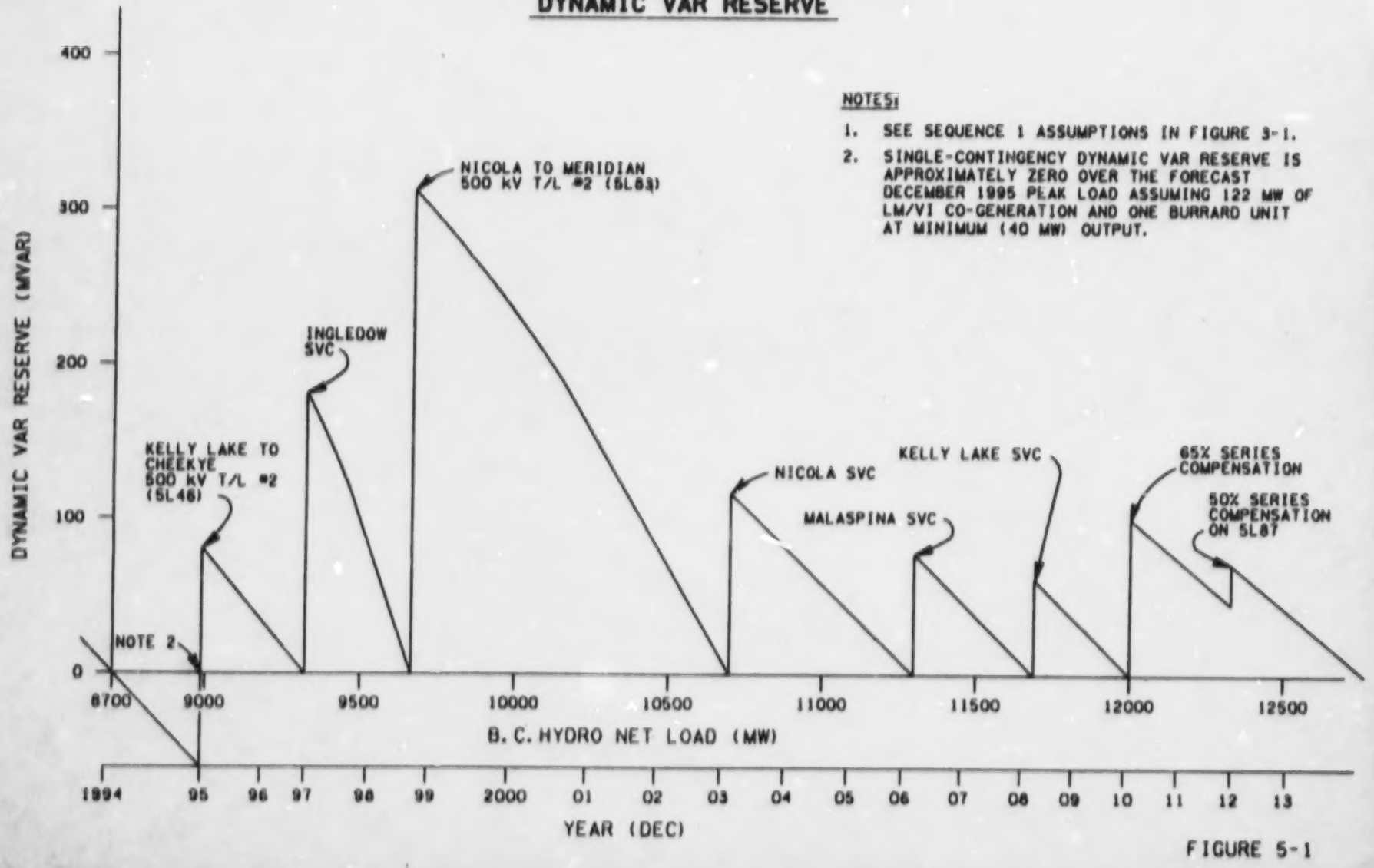


FIGURE 5-1

INTERIOR TO LOWER MAINLAND TRANSMISSION REINFORCEMENT
SEQUENCE 2
STAGING AND SINGLE - CONTINGENCY
DYNAMIC VAR RESERVE

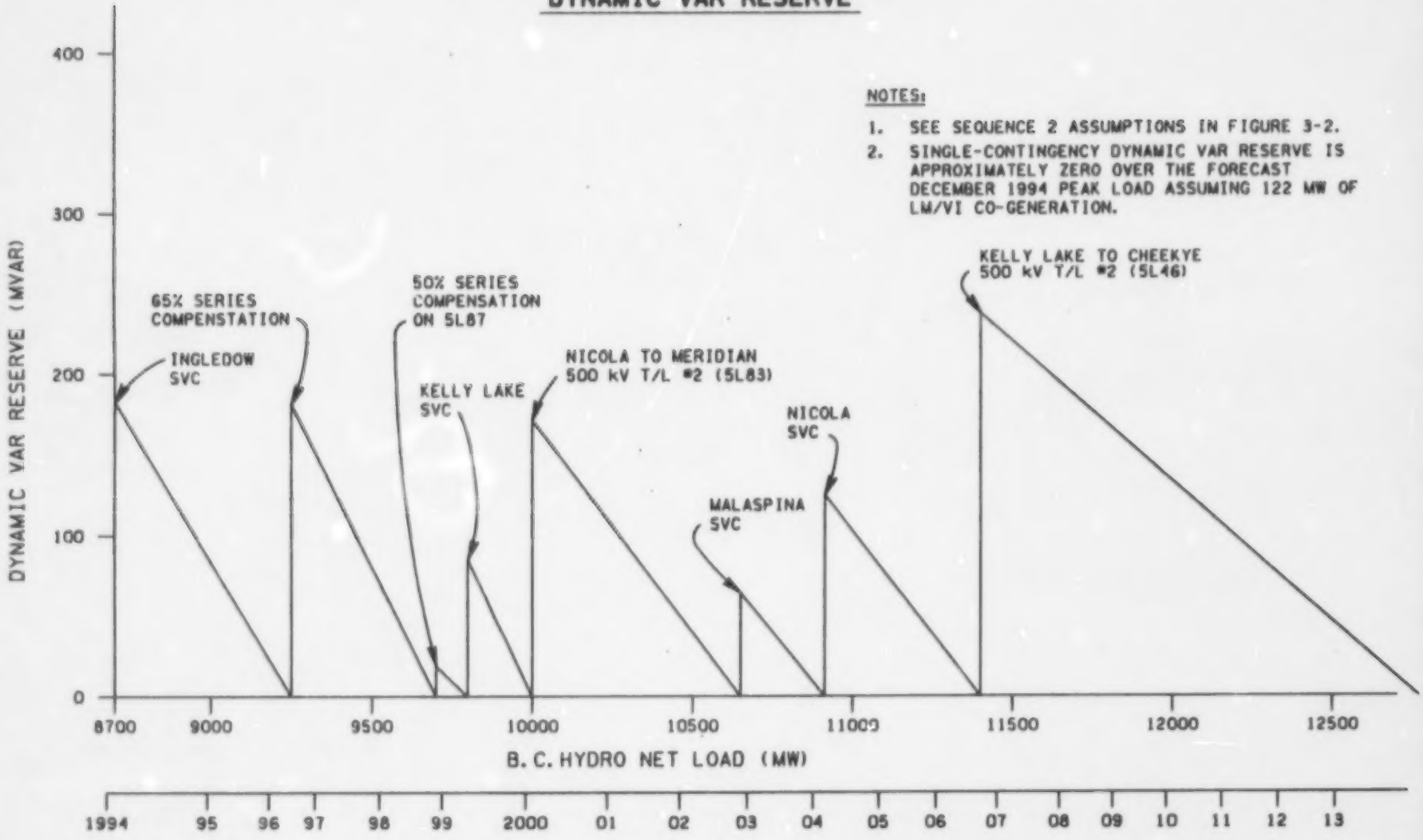
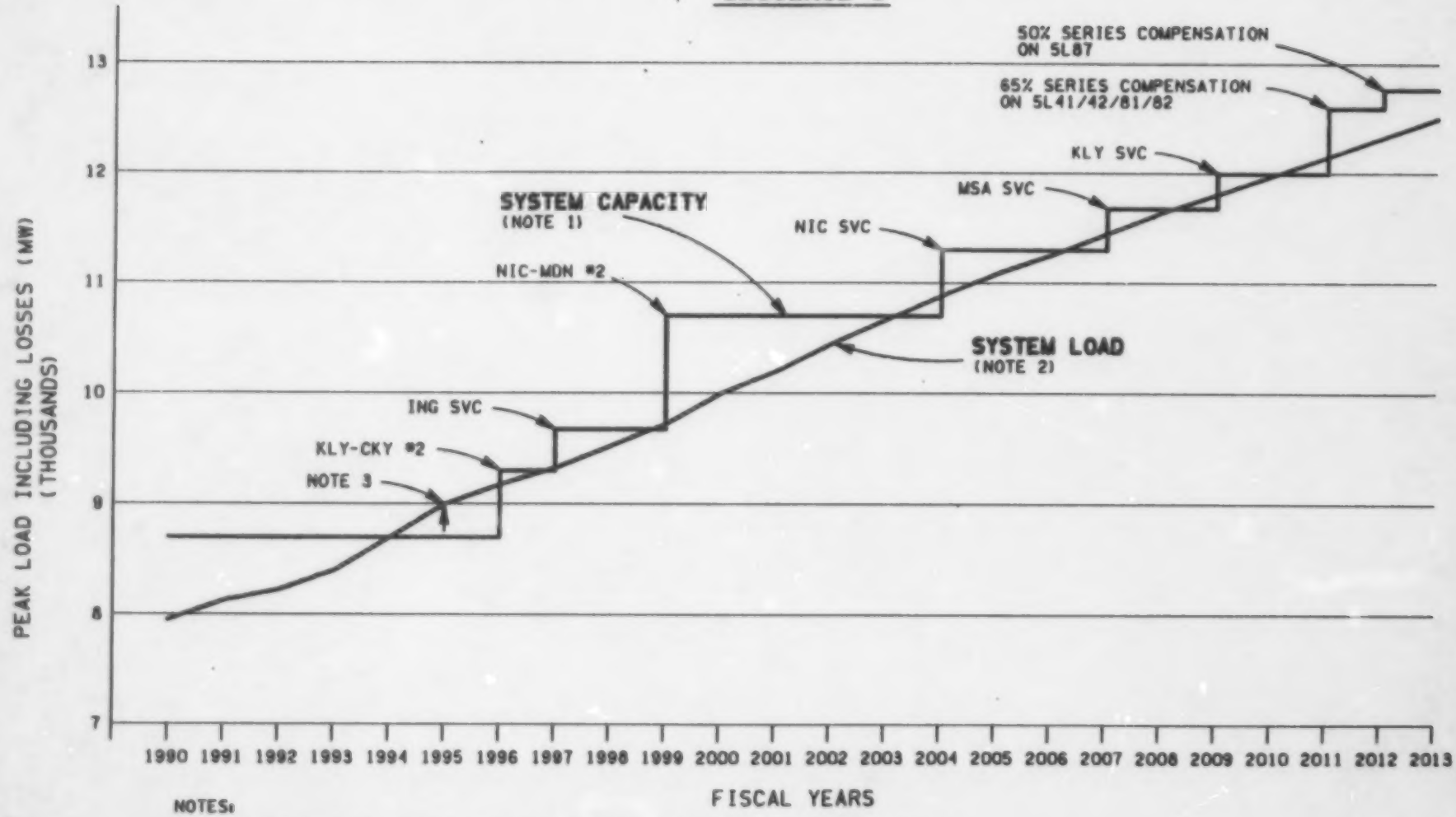


FIGURE 5-2

441/CJB.DGN

B. C. HYDRO NET LOAD VS FIRM TRANSMISSION CAPABILITY FOR SEQUENCE 1



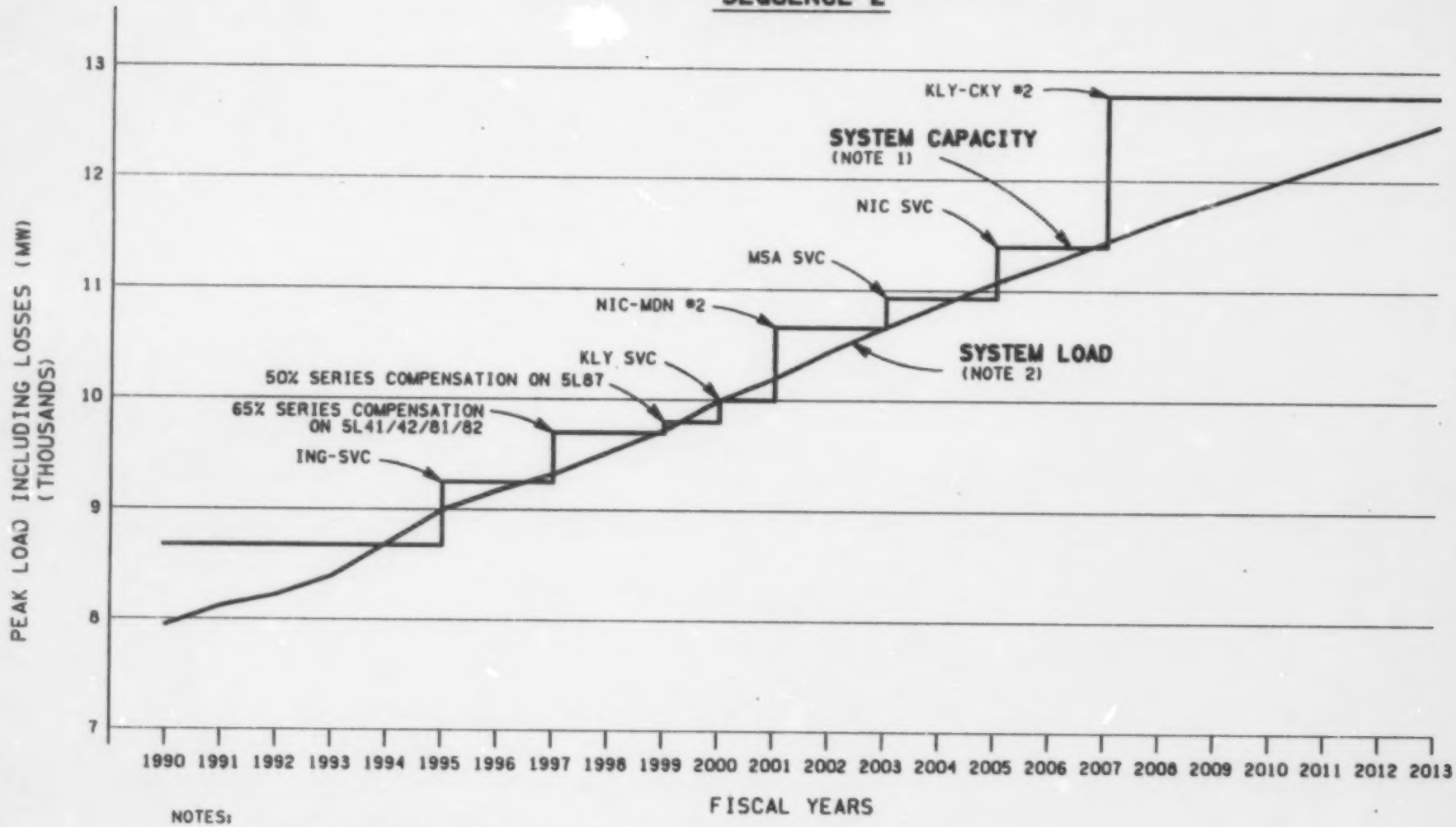
NOTES:

1. CAPABILITY STEPS ARE DERIVED FROM THE DYNAMIC VAR RESERVE (MVAR) INCREASES SHOWN IN FIGURE 5-1.
2. B.C. HYDRO INTEGRATED SYSTEM NET LOAD IS THE FORECAST (SEPT '90) PROBABLE PEAK CONNECTED LOAD PLUS LOSSES AND INCLUDES ALLOWANCE FOR DSM, AND E+ PROGRAMS, AND ZERO VANCOUVER ISLAND (NET) LOAD GROWTH AFTER 2002.
3. ONE TIME USE OF A SINGLE BURRARD UNIT AT MINIMUM OUTPUT (40 MW) WILL PROVIDE THE REQUIRED FIRM TRANSMISSION CAPABILITY OVER 1995/96 PEAK LOAD.

FIGURE 5-3

441/CJ8.DGN

B.C. HYDRO NET LOAD VS FIRM TRANSMISSION CAPABILITY FOR SEQUENCE 2



NOTES:

1. CAPABILITY STEPS ARE DERIVED FROM THE DYNAMIC VAR RESERVE (MVAR) INCREASES SHOWN IN FIGURE 5-2.
2. B.C. HYDRO INTEGRATED SYSTEM NET LOAD IS THE FORECAST (SEPT '90) PROBABLE PEAK CONNECTED LOAD PLUS LOSSES AND INCLUDES ALLOWANCE FOR DSM, AND E+ PROGRAMS, AND ZERO VANCOUVER ISLAND (NET) LOAD GROWTH AFTER 2002.

FIGURE 5-4

APPENDIX 6

LINE LOSSES

LINE LOSSES

FIGURES

6-1 TOTAL SYSTEM LINE LOSS REDUCTION

TOTAL SYSTEM LINE LOSS REDUCTION

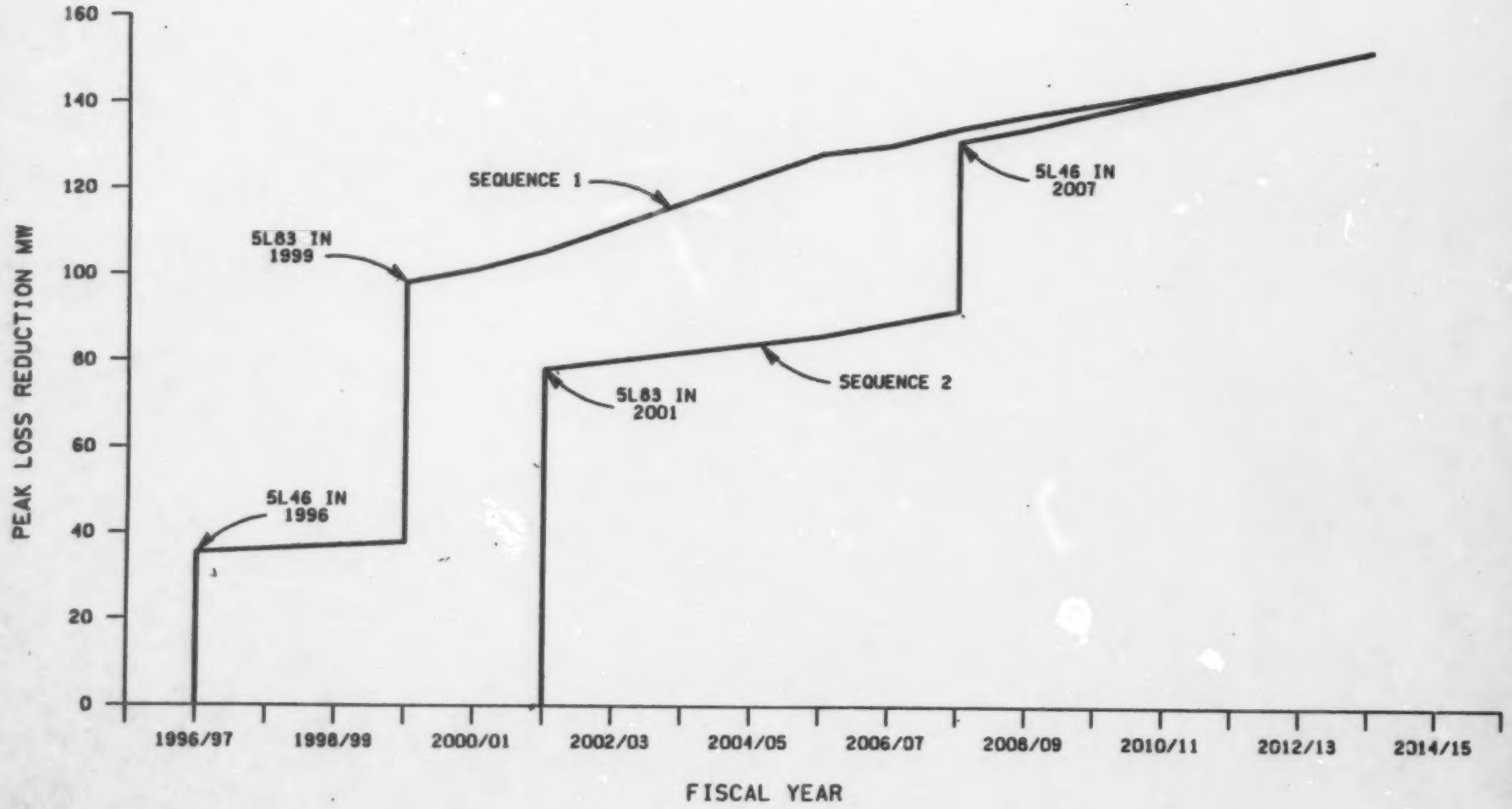


FIGURE 6-1

APPENDIX 7

ECONOMIC ANALYSIS

ECONOMIC ANALYSIS

TABLES

7-1 ANNUAL COST FACTORS - 8% DISCOUNT RATE

7-2 MARGINAL COST OF ELECTRICITY DELIVERED TO THE LOWER MAINLAND

7-3 SUMMARY TABLE: AGGREGATE NET PRESENT VALUE

7-4 SUMMARY TABLE: LONG-TERM PAYBACK OF CIRCUIT 5L46

7-5 ECONOMIC ANALYSIS OF SEQUENCE 1 (EARLY TRANSMISSION)

7-6 ECONOMIC ANALYSIS OF SEQUENCE 2 (DEFERRED TRANSMISSION)

TABLE 7-1 8% DISCOUNT RATE

TYPICAL ANNUAL COST FACTORS TO APPLY TO DIRECT PROJECT COSTS

Annual cost factors below are for typical projects. Corporate overhead is now at the same rate for all projects. Interest during construction allocations will vary depending on project schedules. However, the annual cost factors are accurate within 10 percent for most projects in the categories given below

Capital Cost	(a)*Major Lines	(b)*Intermediate Lines, Major Substations and M/W	(c)* Minor Lines Minor Sub-stations and M/W
Direct Construction Cost	100.0	100.0	100.0
Corporate Overhead (CO)	8.0	8.0	8.0
Interest During Construction (IDC) at 8% discount rate			
a. 13% of 108%	14.0		
b. 7% of 108%		7.6	
c. 4% of 108%			4.3
Total Capital Costs (% of Direct Costs)	122.0	115.6	112.3

PERCENT ANNUAL COST FACTORS AT 8% DISCOUNT RATE

	Transmission Lines				Substations		Microwave	
	Steel Tower	U/G Cable	Wood Pole (Major)	Wood Pole (Minor)	Major Add'ns	Minor Add'ns	Major Add'ns	Minor Add'ns
Interest & Depreciation								
Steel Tower T/L 8.26% of 122.0	10.08							
Cable, Wood Pole T/L substation additions, 8.88% of 115.6		10.27	10.27		10.27			
				9.97		9.97		
Minor lines, station, additions, 8.88% of 112.3								
Major M/W, 10.18% of 115.6							11.77	
Minor M/W, 10.18% of 112.3								11.43
Operating & Maintenance	0.6	0.1	1.2	1.2	1.2	1.2	5.0	5.0
Total Excluding Taxes	10.68	10.37	11.47	11.17	11.47	11.17	16.77	16.43
Taxes	1.3	.1	.7	.7	0	0	0	0
Total Including Taxes	11.98	10.47	12.17	11.87	11.47	11.17	16.77	16.43
Rounded Annual Cost Factors	12.0	10.5	12.2	11.9	11.5	11.2	16.8	16.4

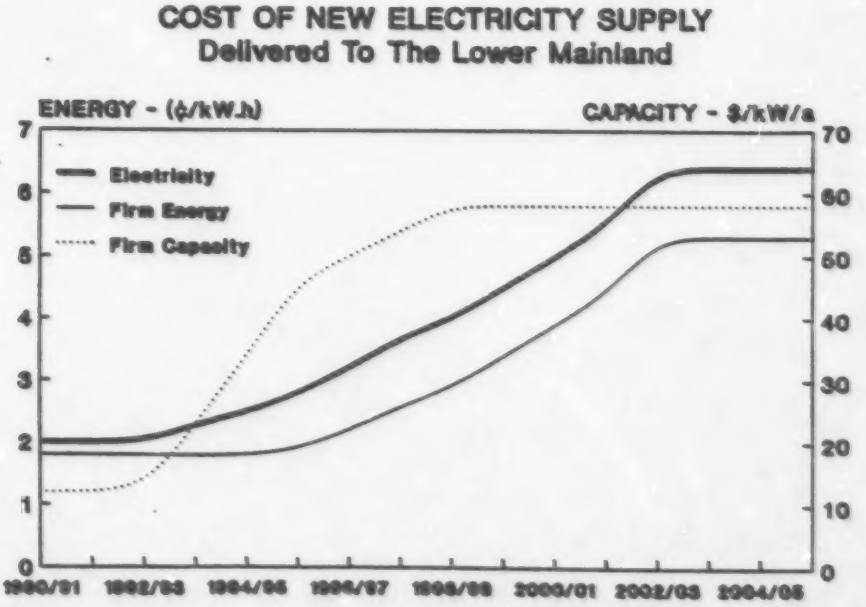
December 1990

TABLE 7-2

COST OF NEW ELECTRICITY SUPPLY DELIVERED TO THE LOWER MAINLAND
October 1990 Dollars

	Electricity[1] (¢/kW·h)	Firm Capacity $/kW/a	Energy (¢/kW·h)
1990/91	2.0	12	1.8
1991/92	2.0	12	1.8
1992/93	2.0	12	1.8
1993/94	2.3	23	1.8
1994/95	2.5	34	1.8
1995/96	2.8	46	1.9
1996/97	3.2	50	2.2
1997/98	3.7	54	2.6
1998/99	4.0	58	2.9
1999/00	4.5	58	3.4
2000/01	5.0	58	3.9
2001/02	5.5	58	4.4
2002/03 on	6.4	58	5.3

[1] The capacity factor of the B.C. Hydro system is about 65% or 58% after allowing for a 12% reserve margin. Therefore, on average each kW of installed capacity would produce 5080 kW.h/year (0.58 kW x 8760 hours/year). Based on these values a capacity cost of $1/kW/year is equivalent to 1/5080 = 0.0197¢/kW.h.



From Exhibit 1 of B.C. Hydro's The Cost of New Electricity Supply in British Columbia, Resource Planning, Corporate and Environmental Affairs, December 1990.

TABLE 7-3

AGGREGATE NET PRESENT VALUE (NPV)

	At 6% Discount Rate		At 8% Discount Rate		At 10% Discount Rate	
	$ Million		$ Million		$ Million	
	Sequence 1	Sequence 2	Sequence 1	Sequence 2	Sequence 1	Sequence 2
Present Value, Aggregate Annual Costs*	$412	$356	$349	$287	$305	$238
Transmission Loss Savings	$421	$333	$280	$209	$194	$136
Total Aggregate NPV (net of losses)	-$9	+$23	$69	$78	$111	$102
Sequence 1 - Sequence 2 Difference	-$32		-$9 (base case)		+$9	

* Annual costs include charges for interest, depreciation, operating and maintenance and taxes for all projects in the sequence.

TABLE 7-4

LONG TERM PAY BACK OF CIRCUIT 5L46

	Net Present Value		
	At 6% Discount Rate	At 8% Discount Rate	At 10% Discount Rate
	$ Million	$ Million	$ Million
Present Value, Project Costs*	$150.7	$135.2	$124.3
Transmission Loss Savings	$171.6	$116.1	$ 81.9
Pay Back (over 45 year lifetime)	114%	86%	66%

* Annual costs include charges for interest, depreciation, operation and maintenance and taxes for the Kelly Lake to Cheekye project only.

INTERIOR TO LOWER MAINLAND 500 KV REINFORCEMENT
ECONOMIC ANALYSIS - SEQUENCE 1

MAR 1 5 1991

ECONOMIC ASSUMPTIONS:

DISCOUNT RATE =	0.08
STEEL TA. ACF =	0.095
MAJ SUBSAHOOD TA. ACF	0.100
SYSTEM LOSS FACTOR =	0.60

NET COST SUMMARY:

AGGREGATE	69912
KLY-GKY 2 (5L46)	10160
NIC-MDN 2 (5L89)	-21664
OTHER	71567

BASEPLAN (8% Disc. Rate, 64 mills/kWh, 0.60 Loss Factor, 5L46 Probable Cost)

TABLE 7-5

DIRECT COST SUMMARY ($000'S)
Expenditure for Fiscal Year Beginning 1 April

TA.INE 1: 5L46	TOTAL	81	82	83	84	85	86	87	88	89	0	1	2	3	4	5	6	7	8	9	10	11	12
500 KV TA.INE	114043	3881	5064	6888	29036	43441	22264	1183	106	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KELLY LAKE	11641	0	0	47	182	4867	6346	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CHEEKYE	2088	0	0	88	84	1809	474	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CREEKSIDE	8648	0	15	169	808	6364	2306	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SL1 REMOVAL	7520	0	85	3760	3746	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MISC.	1848	0	334	1312	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	144456	3881	5438	16157	33629	55181	31548	1183	106	0	0	0	0	0	0	0	0	0	0	0	0	0	0

TA.INE 2: SL89	TOTAL	81	82	83	84	85	86	87	88	89	0	1	2	3	4	5	6	7	8	9	10	11	12
500 KV TA.INE	175888	0	1541	995	3888	8803	22264	63364	41388	30044	2034	0	0	0	0	0	0	0	0	0	0	0	0
NICOLA	7500	0	0	0	0	0	148	780	3001	3801	0	0	0	0	0	0	0	0	0	0	0	0	0
MERIDIAN	8810	0	0	0	0	0	0	561	2284	2906	0	0	0	0	0	0	0	0	0	0	0	0	0
AMC	10400	0	0	0	0	0	100	1339	6040	2927	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	197588	0	1541	995	3888	8803	22512	66028	52730	39677	2034	0	0	0	0	0	0	0	0	0	0	0	0

STAT VAR COMP:	TOTAL	81	82	83	84	85	86	87	88	89	0	1	2	3	4	5	6	7	8	9	10	11	12
INGLEDOW	19000	0	0	0	160	3040	13300	2470	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KELLY LAKE	26400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	280	4200	16640	3400	0	0	0
NICOLA	26400	0	0	0	0	0	0	0	0	0	0	280	4200	16640	3400	0	0	0	0	0	0	0	0
MALASPINA	26400	0	0	0	0	0	0	0	0	0	0	0	0	0	280	4200	16640	3400	0	0	0	0	0
TOTAL	98200	0	0	0	160	3040	13300	2470	0	0	0	280	4200	16640	3680	4200	16800	7600	16640	3400	0	0	0

OTHER:	TOTAL	81	82	83	84	85	86	87	88	89	0	1	2	3	4	5	6	7	8	9	10	11	12
50% S.CX SL41/42/61/62	27740	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	560	2700	10800	13680	0
50% S.CX SL46/89	10630	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	251	1074	4381	4826	0
50% S.CX SL87	11498	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	113	1498	8555	3335
BUT 40 MW GEN	3360	0	0	0	0	3360	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	53130	0	0	0	0	3360	0	0	0	0	0	0	0	0	0	0	0	0	831	3887	16776	34941	3335

CASH FLOW SUMMARY ($000'S)
Expenditures for Fiscal Year Beginning 1 April

TA.BNE 1: $4.48	81	82	83	84	85	86	87	88	89	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
500 KV TA.BNE	376	800	1668	5245	10539	14806	14797	14747	14747	14747	14747	14747	14747	14747	14747	14747	14747	14747	14747	14747	14747	14747	14747
KELLY LAKE	0	0	5	25	550	1257	1257	1257	1257	1257	1257	1257	1257	1257	1257	1257	1257	1257	1257	1257	1257	1257	1257
CHEEKYE	0	0	3	8	172	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223
CREEKSIDE	0	2	16	105	666	933	933	933	933	933	933	933	933	933	933	933	933	933	933	933	933	933	933
SL1 REMOVAL/MISC.	0	39	580	990	990	990	990	990	990	990	990	990	990	990	990	990	990	990	990	990	990	990	990
NET TAXES	0	0	-438	-439	-439	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424
TOTAL	376	800	1668	5245	10539	14806	14797	14747	14747	14747	14747	14747	14747	14747	14747	14747	14747	14747	14747	14747	14747	14747	14747

TA.BNE 2: $4.89	81	82	83	84	85	86	87	88	89	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
500 KV TA.BNE	0	146	241	591	1408	3524	9543	13473	16327	16520	16520	16520	16520	16520	16520	16520	16520	16520	16520	16520	16520	16520	16520
NICOLA	0	0	0	0	0	16	97	421	810	810	810	810	810	810	810	810	810	810	810	810	810	810	810
MERRIMAN	0	0	0	0	0	0	69	314	627	627	627	627	627	627	627	627	627	627	627	627	627	627	627	627
AMC	0	0	0	0	0	11	166	807	1123	1123	1123	1123	1123	1123	1123	1123	1123	1123	1123	1123	1123	1123	1123
TAXES	0	0	0	0	0	0	0	0	1046	1046	1046	1046	1046	1046	1046	1046	1046	1046	1046	1046	1046	1046	1046
TOTAL	0	146	241	591	1408	3550	9855	15015	19933	20126	20126	20126	20126	20126	20126	20126	20126	20126	20126	20126	20126	20126	20126

STAT VAR COMP:	81	82	83	84	85	86	87	88	89	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
SKEEDOW	0	0	0	21	349	1766	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052
KELLY LAKE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28	482	2484	2851	2851	2851	2851	2851
NICOLA	0	0	0	0	0	0	0	0	0	0	28	482	2484	2851	2851	2851	2851	2851	2851	2851	2851	2851	2851
MALASPINA	0	0	0	0	0	0	0	0	0	0	0	0	0	28	482	2484	2851	2851	2851	2851	2851	2851	2851
TOTAL	0	0	0	21	349	1766	2052	2052	2052	2052	2080	2534	4536	4931	5385	7415	8236	10039	10606	10606	10606	10606	10606

OTHER:	81	82	83	84	85	86	87	88	89	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
60% S.GX SL41/42/140	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	68	354	1831	2956	2956	2956
60% S.GX SL46/80	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	27	143	616	1137	1137	1137
60% S.GX SL87	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	12	174	852	1242	1242
BUT 40 MW GEN	0	0	0	0	3350	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	3350	0	0	0	0	0	0	0	0	0	0	0	0	90	510	2621	4945	5335	5335

SEQUENCE 1

PRESENT VALUE CASH FLOW ($000'S)
Expenditures for Fiscal Year Beginning 1 April

TALINE 1: SL49	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
500 KV TALINE	101673	350	737	1426	3348	5909	6804	6366	6900	6483	5958	4883	4336	4015	3718	3442	3187	2961	2733	2530	2343	2169	2009	22187
KELLY LAKE	10757	0	0	4	16	375	762	734	679	629	582	539	499	462	428	396	367	340	315	291	270	250	231	2668
CHEEKYE	1961	0	0	2	6	117	140	130	120	111	103	96	88	82	76	70	65	60	56	52	48	44	41	453
CREEKSIDE	8251	0	1	14	77	486	588	545	504	467	432	400	371	343	318	294	272	252	234	216	200	185	172	1907
SL1 REMOVALS/MISC.	10057	0	33	465	728	674	624	578	535	495	459	425	393	364	337	312	289	268	248	229	212	197	182	2012
NET TAXES	2524	0	0	-348	-323	-299	267	247	229	212	196	182	168	156	144	134	124	115	106	98	91	84	78	982
TOTAL	135224	350	771	1563	3856	7241	9216	8599	7967	7377	6831	6325	5858	5422	5021	4648	4305	3988	3690	3417	3184	2930	2713	29677

TALINE 2: SL45	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
500 KV TALINE	123846	0	126	191	435	909	2230	5566	7276	8186	7862	7096	6960	6074	5625	5208	4822	4465	4134	3828	3544	3282	3039	33682
NICOLA	5649	0	0	0	0	0	10	57	228	405	375	347	322	298	276	256	236	219	203	188	174	161	148	1647
MERIDIAN	4278	0	0	0	0	0	0	37	170	314	291	269	249	231	214	198	183	170	157	145	135	125	115	1276
AMC	7918	0	0	0	0	0	7	90	430	862	520	482	446	413	382	354	329	304	281	260	241	223	207	2383
TAXES	6779	0	0	0	0	0	0	0	0	523	484	448	415	384	356	329	305	282	262	242	224	208	192	2134
TOTAL	148280	0	126	191	435	909	2237	5752	8112	9771	9322	8632	7992	7400	6852	6345	5875	5438	5037	4663	4318	3998	3702	40911

STAT VAR COMP:	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
INGLEDOW	14884	0	0	0	15	237	1126	1167	1109	1027	950	880	815	755	699	647	599	555	514	476	440	408	377	4171
KELLY LAKE	8918	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	130	852	881	812	586	834	5798
NICOLA	13462	0	0	0	0	0	0	0	0	0	0	12	191	813	871	899	832	771	714	661	612	566	524	5798
MALASPINA	10530	0	0	0	0	0	0	0	0	0	0	0	0	0	10	152	725	771	714	661	612	566	524	5798
TOTAL	48805	0	0	0	15	237	1126	1167	1109	1027	950	892	1006	1568	1579	1698	2164	2226	2862	2467	2275	2107	1961	21566

OTHER:	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
69% B.CX SL41/42/61/62	7962	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	82	329	886	851	6060
69% B.C SL66/83	2818	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	33	132	336	309	2312
50% B.CX SL87	2966	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	37	175	229	2524
BUT 40 MW GEN	2280	0	0	0	0	2280	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	15630	0	0	0	0	2280	0	0	0	0	0	0	0	0	0	0	0	0	22	118	498	996	989	10896

SEQUENCE 1

LOSS SUMMARY

Expenditures for Fiscal Year Beginning 1 April

	TOTAL	81	82	83	84	85	86	87	88	89	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
ELECTY VALUE ($/MWH)		20	20	23	25	28	32	37	40	45	50	55	64	64	64	64	64	64	64	64	64	64	64	64
CAPCTY VALUE ($/KWA)		12	12	23	34	46	60	64	64	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
ENERGY VALUE ($/MWH)		18	18	18	18	19	22	26	29	34	39	44	53	53	53	53	53	53	53	53	53	53	53	53
1) ADD SL46																								
W/O VI 500 KV		0	0	0	0	0	35	36	37	38	39	40	42	46	47	50	50	51	52	53	54	55	56	57
W VI 500 KV		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL SL46		0	0	0	0	0	35	36	37	38	39	40	42	46	47	50	50	51	52	53	54	55	56	57
ELECTCTY LOSS ($)		0	0	0	0	0	6987	7001	7779	8966	10049	11583	14139	16137	16810	16819	16810	17166	17492	17838	18185	18501	18856	19174
NPV ELECTY LOSS($)	116139	0	0	0	0	0	3710	4086	4203	4486	4747	4969	5610	5566	5363	5302	4868	4607	4377	4131	3987	3676	3466	39876
CAPCTY LOSS ($)		0	0	0	0	0	1760	1944	2146	2304	2262	2300	2430	2610	2736	2900	2900	2956	3016	3074	3132	3190	3248	3306
ENERGY LOSS ($)		0	0	0	0	0	4047	4680	5640	6781	7994	8251	11700	12536	13060	13526	13689	14207	14488	14764	15043	15301	15600	15878
TOTAL LOSS ($)		0	0	0	0	0	5787	6624	7786	8966	10256	11571	14130	15146	15810	16826	16589	17166	17502	17838	18175	18511	18846	19184
NPV TOTAL LOSS($000'S	116056	0	0	0	0	0	3693	4006	4206	4800	4751	4962	5614	5566	5366	5305	4912	4639	4360	4130	3966	3677	3467	39867
2) ADD SL83																								
W/O VI 500 KV		0	0	0	0	0	0	0	0	60	62	65	69	72	75	78	80	83	86	89	89	90	93	95
W VI 500 KV		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL SL83		0	0	0	0	0	0	0	0	60	62	65	69	72	75	78	80	83	86	89	89	90	93	95
ELECTCTY LOSS ($)		0	0	0	0	0	0	0	0	14191	16394	18790	23210	34200	35839	36236	36911	37580	38083	38539	39482	39876	31884	31990
NPV ELECTY LOSS($)	170017	0	0	0	0	0	0	0	0	7068	7947	9058	9217	9806	9589	9271	7886	7648	7196	6705	6351	6014	5764	64999
CAPCTY LOSS ($)		0	0	0	0	0	0	0	0	3480	3686	3770	4002	4176	4350	4524	4640	4814	4930	4966	5104	5220	5394	5810
ENERGY LOSS ($)		0	0	0	0	0	0	0	0	10722	12709	19032	19221	20067	20993	21728	22385	23121	23679	23967	24614	25071	25607	26494
TOTAL LOSS ($)		0	0	0	0	0	0	0	0	14202	16305	18802	23223	24233	25243	26252	26925	27936	28608	28945	29618	30891	31301	31974
NPV TOTAL LOSS($000'S	170123	0	0	0	0	0	0	0	0	7105	7962	8064	9222	9810	9594	9276	7899	7660	7196	6707	6364	6016	5767	64996
3) ADD NON-TRANSMISSION																								
SVC'S		0	0	0	0	0	0	-1	-1	-1	-1	-1	-1	-1	-2	-2	-2	-3	-3	-4	-4	-4	-4	-4
OTHER		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL NON-TAMISSION		0	0	0	0	0	0	-1	-1	-1	-1	-1	-1	-1	-2	-2	-2	-3	-3	-4	-4	-4	-4	-4
ELECTCTY LOSS ($)		0	0	0	0	0	0	-184	-210	-237	-263	-290	-336	-336	-473	-473	-473	-1009	-1009	-1346	-1346	-1346	-1346	-1346
NPV ELECTY LOSS($)	-5862	0	0	0	0	0	0	-113	-114	-116	-122	-134	-134	-134	-229	-212	-186	-273	-260	-312	-286	-267	-247	-2726
CAPCTY LOSS ($)		0	0	0	0	0	0	-84	-84	-86	-86	-88	-86	-88	-110	-116	-116	-174	-174	-232	-232	-232	-232	-232
ENERGY LOSS ($)		0	0	0	0	0	0	-137	-162	-179	-305	-231	-279	-270	-567	-567	-567	-836	-836	-1114	-1114	-1114	-1114	-1114
TOTAL LOSS ($)		0	0	0	0	0	0	-191	-210	-237	-263	-290	-337	-337	-673	-673	-673	-1010	-1010	-1346	-1346	-1346	-1346	-1346
NPV TOTAL LOSS($000'S	-5862	0	0	0	0	0	0	-111	-114	-116	-122	-134	-134	-134	-329	-212	-186	-273	-253	-312	-286	-267	-246	-2797

SEQUENCE 1

NET PRESENT VALUE-AGGREGATE ($000'S)
Expenditures for Fiscal Year Beginning 1 April

	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
NPV CAPITAL	348228	350	897	1755	4305	10717	12578	15648	17188	18375	17103	15848	14866	14491	13852	12891	12344	11651	11312	10890	10258	10031	9264	103372
NPV DELTA LOSS	250316	0	0	0	0	0	3953	3894	4083	11486	12181	12902	14702	14356	13751	13389	12575	11916	11286	10626	9965	9427	8877	101265
NPV TOTAL	98912	350	897	1755	4305	10717	8625	11854	13085	6889	4922	2946	163	135	-199	-678	-231	-265	25	128	293	603	377	2117

CUMULATIVE PRESENT VALUE-AGGREGATE ($000'S)

		91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
CPV CAPITAL		350	1247	3002	7306	18023	30602	46150	63338	81713	98816	114665	129513	144010	157862	170753	183098	194747	206059	216815	226470	236501	245855	349228
CPV DELTA LOSS		0	0	0	0	0	3953	7847	11939	23425	35607	48509	62911	77267	91017	104388	116981	128877	140163	150691	160656	170084	178961	280316
CPV TOTAL		350	1247	3002	7306	18023	26648	38303	51398	58287	63210	66156	66603	66743	66845	66365	66117	65870	65896	66123	66814	66417	66895	68912

NET PRESENT VALUE - IL40 ($000'S)
Expenditures for Fiscal Year Beginning 1 April

	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
NPV CAPITAL	136294	350	771	1563	3866	7241	8216	8099	7967	7377	6831	6325	5856	5422	5021	4649	4306	3988	3692	3417	3164	2930	2713	28677
NPV DELTA LOSS	118056	0	0	0	0	0	3863	4005	4206	4500	4751	4962	5014	5000	5384	5305	4912	4639	4380	4133	3899	3677	3467	39997
NPV TOTAL	18160	350	771	1563	3866	7241	3563	4094	3761	2878	2080	1362	843	-147	-365	-656	-606	-654	-688	-716	-735	-748	-754	-9320

CUMULATIVE PRESENT VALUE IL40 ($000'S)

		91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
CPV CAPITAL		350	1122	2686	6540	13781	22997	31696	39663	46940	53771	60096	65952	71374	76395	81044	85348	89334	93034	96442	99606	102536	105249	136294
CPV DELTA LOSS		0	0	0	0	0	3863	7868	11864	16364	21115	26077	31091	37280	42645	47950	52862	57502	61881	66016	69914	73591	77058	118056
CPV TOTAL		350	1122	2686	6540	13781	18344	23838	27799	30576	32656	34018	34861	34115	33750	33094	32486	31833	31143	30427	29692	28944	28189	18160

SEQUENCE 1

NET PRESENT VALUE - SL83 ($000'S)
Expenditures for Fiscal Year Beginning 1 April

	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
NPV CAPITAL	148269	0	126	191	435	959	2237	5752	9112	9971	9322	9032	7982	7400	6852	6346	5875	5439	5037	4663	4318	3998	3702	40911
NPV DELTA LOSS	170123	0	0	0	0	0	0	0	0	7106	7552	9064	9222	8910	8594	8276	7959	7650	7169	6707	6364	6016	5757	64995
NPV TOTAL	-21854	0	126	191	435	959	2237	5752	9112	2867	1770	568	-1230	-1510	-1742	-1931	-1985	-2111	-2123	-2043	-2036	-2018	-2056	-24084

CUMULATIVE PRESENT VALUE - SL83 ($000'S)

		91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
CPV CAPITAL		0	126	317	751	1710	3947	9699	17811	27783	37106	46737	53729	61129	67981	74326	80200	85640	90678	95340	99658	103656	107358	148269
CPV DELTA LOSS		0	0	0	0	0	0	0	0	7106	14657	22721	31943	40854	49448	57724	65683	73333	80502	87209	93573	99589	105346	170123
CPV TOTAL		0	126	317	751	1710	3947	9699	17811	20678	22448	23016	21786	20276	18534	16602	14518	12307	10084	8341	6084	4066	2230	-21854

SEQUENCE 1

NET PRESENT VALUE - NON-TRANSMISSION
Expenditures for Fiscal Year Beginning 1 April

	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
NPV CAPITAL	96734	0	0	0	16	2517	1125	1197	1109	1027	950	882	1008	1668	1679	1899	2164	2220	2585	2576	2773	3103	2940	38486
NPV DELTA LOSS	-6868	0	0	0	0	0	0	-111	-114	-118	-122	-124	-134	-134	-229	-212	-163	-373	-293	-312	-288	-367	-348	-2737
NPV TOTAL	71867	0	0	0	16	2517	1125	1308	1222	1145	1072	1016	1140	1792	1908	1910	2361	2490	2837	2887	3062	3371	3187	36221

CUMULATIVE PRESENT VALUE - KLY-CBL 500 KV (80007B)

	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
CPV CAPITAL		0	0	0	16	2532	3657	4866	5923	6950	7940	8833	9839	11507	13186	14893	17047	19273	21858	24434	27207	30310	33250	96734
CPV DELTA LOSS		0	0	0	0	0	0	-111	-225	-343	-466	-590	-723	-847	-1076	-1288	-1484	-1757	-2010	-2322	-2611	-2978	-3326	-6868
CPV TOTAL		0	0	0	16	2532	3657	4866	5698	7333	8406	9422	10662	12369	14381	16171	18532	21031	23868	26756	29818	33188	36576	71867

INTERIOR TO LOWER MAINLAND 500 KV REINFORCEMENT
ECONOMIC ANALYSIS - SEQUENCE 2

MAR 1 5 1991

ECONOMIC ASSUMPTIONS:

DISCOUNT RATE =	0.08
STEEL TA. A.C.F. =	0.095
MAJ SUBS/WOOD TA. A.C.	0.108
SYSTEM LOSS FACTOR =	0.60

NET COST SUMMARY:

AGGREGATE	78891
KLY-CKY 2 (5L46)	10368
NIC-MDN 2 (5L83)	-51784
OTHER	120107

BASEPLAN (8% Disc. Rate, 64 mills/kWh, 0.60 Loss Factor, 5L46 Probable Cost)

TABLE 7-6

DIRECT COST SUMMARY ($000'S)
Expenditure for Fiscal Year Beginning 1 April

TA.LINE 1: 5L46	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12
500 KV TA.LINE	117501	0	0	0	0	0	0	0	0	0	880	1678	3981	5084	9889	29035	43441	22284	1183	106	0	0	0
KELLY LAKE	11841	0	0	0	0	0	0	0	0	0	0	0	0	0	47	182	4867	6545	0	0	0	0	0
CHEEKYE	2083	0	0	0	0	0	0	0	0	0	0	0	0	0	28	84	1509	474	0	0	0	0	0
CREEKSIDE	8943	0	0	0	0	0	0	0	0	0	0	0	0	15	153	808	5364	2306	0	0	0	0	0
2L1 REMOVE	7520	0	0	0	0	0	0	0	0	0	0	0	0	25	3750	3745	0	0	0	0	0	0	0
MISC.	1646	0	0	0	0	0	0	0	0	0	0	0	0	334	1312	0	0	0	0	0	0	0	0
TOTAL	149014	0	0	0	0	0	0	0	0	0	880	1678	3981	5438	15157	33822	55181	31588	1183	106	0	0	0

TA.INE 2: 5L83	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12
500 KV TA.LINE	173888	0	0	0	1541	995	3688	8903	22284	63364	41365	30044	2034	0	0	0	0	0	0	0	0	0	0
NICOLA	7500	0	0	0	0	0	0	0	148	750	3001	3601	0	0	0	0	0	0	0	0	0	0	0
MERIDIAN	5810	0	0	0	0	0	0	0	0	581	2324	2905	0	0	0	0	0	0	0	0	0	0	0
AMC	10400	0	0	0	0	0	0	0	100	1333	6040	2927	0	0	0	0	0	0	0	0	0	0	0
MISC.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	197808	0	0	0	1541	995	3688	8903	22512	66028	52730	39477	2034	0	0	0	0	0	0	0	0	0	0

STAT VAR COMP:	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12
INGLEDOW	19000	0	190	3040	13300	2470	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KELLY LAKE	28400	0	0	0	0	0	0	280	4200	18540	3400	0	0	0	0	0	0	0	0	0	0	0	0
NICOLA	28400	0	0	0	0	0	0	0	0	0	0	0	280	4200	18540	3400	0	0	0	0	0	0	0
MALABPWA	28400	0	0	0	0	0	0	0	0	0	280	4200	18540	3400	0	0	0	0	0	0	0	0	0
TOTAL	98200	0	190	3040	13300	2470	0	280	4200	18540	3680	4200	18800	7600	18540	3400	0	0	0	0	0	0	0

OTHER:	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12
60% S.CX 5L41/43/61/62	27740	0	0	0	580	2700	10800	13560	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
60% S.CX 5L46/83	10532	0	0	0	0	0	0	0	108	536	2150	2595	0	143	535	2231	2231	0	0	0	0	0	0
60% S.CX 5L87	11498	0	0	0	0	0	113	1495	6555	3335	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	49770	0	0	0	580	2700	11013	15055	6663	3874	2150	2595	0	143	535	2231	2231	0	0	0	0	0	0

SEQUENCE 2

CASH FLOW SUMMARY ($000'S)

Expenditures for Fiscal Year Beginning 1 April

TALINE 1: SL46	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
500 KV TALINE	0	0	0	0	0	0	0	0	0	84	243	621	1102	2040	4786	8625	11040	11163	11163	11163	11163	11163	11163
KELLY LAKE	0	0	0	0	0	0	0	0	0	0	0	0	0	5	25	550	1257	1257	1257	1257	1257	1257	1257
CHEEKYE	0	0	0	0	0	0	0	0	0	0	0	0	0	3	9	172	223	223	223	223	223	223	223
CREEKSIDE	0	0	0	0	0	0	0	0	0	0	0	0	2	18	106	686	933	933	933	933	933	933	933
2L1 REMOVE/MISC.	0	0	0	0	0	0	0	0	0	0	0	0	39	560	990	990	990	990	990	990	990	990	990
NET TAXES	0	0	0	0	0	0	0	0	0	0	0	0	-439	-439	-439	424	424	424	424	424	424	424	424
TOTAL	0	0	0	0	0	0	0	0	0	84	243	621	704	2212	5488	11746	14888	14990	14990	14990	14990	14990	14990

TALINE 2: SL60	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
500 KV TALINE	0	0	0	146	241	591	1408	3524	9643	13473	16327	16520	16520	16520	16520	16520	16520	16520	16520	16520	16520	16520	16520
NICOLA	0	0	0	0	0	0	0	16	97	421	810	810	810	810	810	810	810	810	810	810	810	810	810
MERIDIAN	0	0	0	0	0	0	0	0	63	314	627	627	627	627	627	627	627	627	627	627	627	627	627
AMC	0	0	0	0	0	0	0	11	155	807	1123	1123	1123	1123	1123	1123	1123	1123	1123	1123	1123	1122	1123
TAXES	0	0	0	0	0	0	0	0	0	0	1045	1045	1045	1045	1045	1045	1045	1045	1045	1045	1045	1045	1045
TOTAL	0	0	0	146	241	591	1408	3550	9858	15015	19933	20126	20126	20126	20126	20126	20126	20126	20126	20126	20126	20126	20126

STAT VAR COMP:	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
INGLEDOW	0	21	348	1786	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052	2052
KELLY LAKE	0	0	0	0	0	0	28	482	2484	2851	2851	2851	2851	2851	2851	2851	2851	2851	2851	2851	2851	2851	2851
NICOLA	0	0	0	0	0	0	0	0	0	0	0	28	482	2484	2851	2851	2851	2851	2851	2851	2851	2851	2851
MALASPINA	0	0	0	0	0	0	0	0	0	28	482	2484	2851	2851	2851	2851	2851	2851	2851	2851	2851	2851	2851
TOTAL	0	21	348	1786	2052	2052	2080	2534	4536	4931	5385	7415	8236	10239	10806	10809	10808	10806	10806	10806	10806	10806	10806

OTHER:	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
66% S.CX SL41/42/61/62	0	0	0	63	364	1531	2996	2996	2996	2996	2996	2996	2996	2996	2996	2996	2996	2996	2996	2996	2996	2996	2996
66% S.CX SL46/63	0	0	0	0	0	0	0	12	70	302	582	582	696	696	807	1137	1137	1137	1137	1137	1137	1137	1137
66% S.CX SL67	0	0	0	0	0	12	174	862	1242	1242	1242	1242	1242	1242	1242	1242	1242	1242	1242	1242	1242	1242	1242
TOTAL	0	0	0	378	2125	9262	19018	23336	25845	27230	28920	28920	29013	29360	30805	32251	32251	32251	32251	32251	32251	32251	32251

SEQUENCE 2

PRESENT VALUE CASH FLOW ($000'S)

Expenditures for Fiscal Year Beginning 1 April

TA.INE 1: 6L48	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
500 KV TA.INE	42325	0	0	0	0	0	0	0	0	0	39	104	247	405	694	1513	2905	2984	2791	2587	2395	2218	2053	22991
KELLY LAKE	4422	0	0	0	0	0	0	0	0	0	0	0	0	0	2	8	161	340	315	291	270	250	231	2566
CHEEKYE	807	0	0	0	0	0	0	0	0	0	0	0	0	0	1	3	50	60	56	52	48	44	41	453
CREEKSIDE	3397	0	0	0	0	0	0	0	0	0	0	0	0	0	1	6	33	200	252	234	216	200	185	172	1887
2L1 REMOVE/MISC.	4183	0	0	0	0	0	0	0	0	0	0	0	0	0	14	199	312	289	268	248	229	212	197	182	2012
NET TAXES	1109	0	0	0	0	0	0	0	0	0	0	0	0	0	-161	-149	-138	124	115	106	98	91	84	78	862
TOTAL	57222	0	0	0	0	0	0	0	0	0	39	104	247	259	753	1730	3428	4018	3740	3473	3216	2978	2767	30471

TA.INE 2: 6L83	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
500 KV TA.INE	105550	0	0	0	108	164	373	822	1904	4774	6241	7002	6560	6074	5625	5208	4822	4465	4134	3828	3544	3282	3039	33562
NICOLA	4726	0	0	0	0	0	0	0	9	49	195	347	322	298	276	255	236	219	203	188	174	161	149	1647
MERIDIAN	3643	0	0	0	0	0	0	0	0	31	145	269	249	231	214	198	183	170	157	145	135	125	115	1276
AMC	6661	0	0	0	0	0	0	0	8	77	374	482	446	413	382	354	328	304	281	260	241	223	207	2283
TAXES	5772	0	0	0	0	0	0	0	0	0	0	448	415	384	356	329	306	282	262	242	224	208	192	2124
TOTAL	126351	0	0	0	108	164	373	822	1918	4931	6955	8549	7992	7400	6852	6345	5875	5439	5037	4663	4318	3998	3702	40911

STAT VAR COMP:	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
INGLEDOW	19913	0	18	277	1312	1397	1293	1197	1109	1027	950	880	815	755	699	647	599	555	514	476	440	408	377	4171
KELLY LAKE	18588	0	0	0	0	0	0	16	260	1243	1321	1223	1132	1048	971	899	832	771	714	661	612	566	524	5796
NICOLA	12408	0	0	0	0	0	0	0	0	0	0	0	11	177	848	899	832	771	714	661	612	566	524	5796
MALASPINA	14689	0	0	0	0	0	0	0	0	0	13	207	998	1048	971	899	832	771	714	661	612	566	524	5796
TOTAL	65599	0	18	277	1312	1397	1293	1214	1369	2269	2284	2309	2945	3028	3488	3343	3096	2868	2654	2467	2275	2107	1951	21559

OTHER:	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
69% S.CX 6L41/42/81/82	24053	0	0	0	46	241	666	1748	1618	1488	1388	1285	1190	1102	1020	944	874	810	750	694	643	595	551	6060
69% S.CX 6L48/83	5567	0	0	0	0	0	0	0	6	35	140	260	231	220	223	283	332	307	285	264	244	226	209	2312
50% S.CX 6L87	8641	0	0	0	0	0	8	101	476	621	575	533	493	457	423	391	362	336	311	288	266	247	228	2524
TOTAL	38260	0	0	0	46	241	973	1849	2101	2165	2103	2067	1914	1778	1666	1618	1569	1453	1346	1245	1153	1068	988	10826

SEQUENCE 2

LOSS SUMMARY

Expenditures for Fiscal Year Beginning 1 April

	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
ELECTY VALUE ($/MWH)		20	20	23	26	28	32	37	40	45	50	55	64	64	64	64	64	64	64	64	64	64	64	64
CAPCTY VALUE ($/KWA)		12	12	23	34	46	50	54	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
ENERGY VALUE ($/MWH)		18	18	18	18	19	22	26	29	34	36	44	53	53	53	53	53	53	53	53	53	53	53	53
1) ADD 6L46																								
W/O VI 500 KV		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	39	39	40	40	41	41	42
W VI 500 KV		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL 6L46		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	39	39	40	40	41	41	42
ELECTCTY LOSS ($)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	13116	13116	13455	13455	13792	13792	14129
NPV ELECY LOSS($)	46829	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3648	3283	3118	2957	2740	2537	26719
CAPCTY LOSS ($)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2282	2282	2320	2320	2378	2378	2436
ENERGY LOSS ($)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10864	10864	11143	11143	11421	11421	11700
TOTAL LOSS ($)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	13126	13126	13463	13463	13799	13799	14136
NPV TOTAL LOSS($000'S	46864	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3648	3285	3119	2958	2741	2538	26735
2) ADD 6L83																								
W/O VI 500 KV		0	0	0	0	0	0	0	0	0	0	78	80	83	84	86	89	92	96	97	101	104	109	110
W VI 500 KV		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL 6L83		0	0	0	0	0	0	0	0	0	0	78	80	83	84	86	89	92	96	97	101	104	109	110
ELECTCTY LOSS ($)		0	0	0	0	0	0	0	0	0	0	23548	26911	27920	28236	28639	29036	30947	31956	32629	33976	34984	36667	37992
NPV ELECY LOSS($)	178037	0	0	0	0	0	0	0	0	0	0	9871	10897	10986	9820	9120	8736	8364	7997	7661	7289	6960	6568	76816
CAPCTY LOSS ($)		0	0	0	0	0	0	0	0	0	0	4434	4640	4814	4872	4969	5162	5339	5610	5636	5868	6032	6146	6260
ENERGY LOSS ($)		0	0	0	0	0	0	0	0	0	0	18039	22295	23121	23400	23867	24793	25828	26484	27021	28135	28971	29588	30842
TOTAL LOSS ($)		0	0	0	0	0	0	0	0	0	0	22583	26925	27936	28272	28845	29966	30964	31974	32647	33883	35003	35878	37022
NPV TOTAL LOSS($000'S	178136	0	0	0	0	0	0	0	0	0	0	9877	10892	10272	9825	9125	8743	8388	8031	7686	7293	6964	6582	71897
3) NON-TRANSMISSION																								
SVC'S		0	0	0	0	-1	-1	-1	-1	-1	-2	-2	-2	-3	-3	-4	-4	-4	-4	-4	-4	-4	-4	-4
INC.COMP		0	0	0	0	0	0	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	0	0	0
TOTAL NON-TAMISSION		0	0	0	0	-1	-1	-7	-7	-7	-8	-8	-8	-9	-9	-10	-10	-10	-10	-10	-10	-4	-4	-4
ELECTCTY LOSS ($)		0	0	0	0	-147	-168	-1361	-1472	-1866	-2102	-2313	-2691	-3027	-3027	-3364	-3364	-3364	-3364	-3364	-3364	-1346	-1346	-1346
NPV ELECY LOSS($)	-16346	0	0	0	0	-100	-109	-794	-795	-829	-974	-992	-1089	-1113	-1031	-1080	-982	-908	-842	-778	-722	-667	-647	-6735
CAPCTY LOSS ($)		0	0	0	0	-46	-50	-378	-406	-406	-464	-464	-464	-522	-522	-580	-580	-580	-580	-580	-580	-232	-232	-232
ENERGY LOSS ($)		0	0	0	0	-100	-116	-867	-1087	-1251	-1640	-1850	-2229	-2507	-2507	-2786	-2786	-2786	-2786	-2786	-2786	-1114	-1114	-1114
TOTAL LOSS ($)		0	0	0	0	-146	-166	-1335	-1473	-1657	-2104	-2314	-2693	-3029	-3029	-3366	-3366	-3366	-3366	-3366	-3366	-1346	-1346	-1346
NPV TOTAL LOSS($000'S	-16807	0	0	0	0	-99	-104	-778	-796	-829	-974	-992	-1089	-1114	-1031	-1081	-982	-910	-842	-780	-722	-667	-648	-6737

SEQUENCE 2

NET PRESENT VALUE AGGREGATE ($000'S)
Expenditures for Fiscal Year Beginning 1 April

	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
NPV CAPITAL	287343	0	18	277	1486	1902	2639	3865	5388	9265	11380	12030	13088	12485	12757	13036	13866	13777	12784	11840	10963	10161	9399	102866
NPV DELTA LOSS	209662	0	0	0	0	-99	-104	-779	-795	-829	-374	8684	9623	9158	8594	8064	7761	11007	10444	9904	9480	9427	8883	101256
NPV TOTAL	78681	0	18	277	1486	1901	2743	4664	6184	10184	12355	3346	3475	3308	4163	4973	6207	2770	2340	1936	1503	733	516	2611

CUMULATIVE PRESENT VALUE AGGREGATE ($000'S)

	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
CPV CAPITAL	0	18	295	1780	3682	6320	10185	15474	24839	36209	48239	61237	74802	87560	100686	114563	128340	141105	152984	163927	174076	183476	287343
CPV DELTA LOSS	0	0	0	0	-99	-204	-982	-1778	-2607	-3882	5103	14726	23884	32478	40542	48303	58309	69753	79658	89117	98544	107397	208662
CPV TOTAL	0	18	295	1780	3681	6404	11068	17252	27438	39791	44137	47511	50919	55082	60064	66261	69031	71371	73307	74810	75533	76079	78681

NET PRESENT VALUE - 9L46 ($000'S)
Expenditures for Fiscal Year Beginning 1 April

	TOTAL	01	02	03	04	05	06	07	08	09	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
NPV CAPITAL	57332	0	0	0	0	0	0	0	0	0	39	104	247	209	753	1730	3429	4018	3748	3473	3216	2978	2757	30471
NPV DELTA LOSS	46954	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3648	3386	3116	2886	2741	2539	28735
NPV TOTAL	10378	0	0	0	0	0	0	0	0	0	39	104	247	259	753	1730	3429	471	464	364	329	237	219	1736

CUMULATIVE PRESENT VALUE 9L46 ($000'S)

	01	02	03	04	05	06	07	08	09	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
CPV CAPITAL	0	0	0	0	0	0	0	0	0	39	143	390	648	1402	3132	6560	10578	14327	17800	21016	23994	26751	57222
CPV DELTA LOSS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3648	6832	9952	12940	15682	18120	46954
CPV TOTAL	0	0	0	0	0	0	0	0	0	39	143	390	648	1402	3132	6560	7031	7494	7848	8176	8413	8632	10268

SEQUENCE 2

NET PRESENT VALUE - M.83 ($000'S)
Expenditures for Fiscal Year Beginning 1 April

	TOTAL	81	82	83	84	85	86	87	88	89	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
NPV CAPITAL	126351	0	0	0	109	164	373	822	1918	4931	8955	8548	7892	7400	6852	6348	5875	5439	5037	4663	4318	3998	3702	40911
NPV DELTA LOSS	178135	0	0	0	0	0	0	0	0	0	0	9677	10592	10272	9525	9125	8743	8368	8001	7565	7293	6954	6582	75257
NPV TOTAL	-51784	0	0	0	109	164	373	822	1918	4931	8955	-1129	-2700	-2871	-2773	-2780	-2869	-2929	-2965	-2901	-2975	-2955	-2880	-34346

CUMULATIVE PRESENT VALUE - M.83 ($000'S)

	81	82	83	84	85	86	87	88	89	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
CPV CAPITAL	0	0	0	109	272	644	1466	3384	8315	15270	23819	31811	39212	46064	52408	58283	63722	68759	73422	77740	81739	85440	126351
CPV DELTA LOSS	0	0	0	0	0	0	0	0	0	0	9677	20269	30541	40066	49191	58134	66503	74504	82069	89362	96316	102870	178135
CPV TOTAL	0	0	0	109	272	644	1466	3384	8315	15270	14142	11442	8671	5798	3218	149	-2781	-5746	-8647	-11622	-14577	-17438	-51784

SEQUENCE: 2

NET PRESENT VALUE - NON-TRANSMISSION ($000'S)
Expenditures for Fiscal Year Beginning 1 April

	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
NPV CAPITAL	103789	0	18	277	1359	1839	2280	3083	3870	4424	4387	4377	4859	4835	5152	4982	4865	4319	3869	3703	2429	3175	2940	39436
NPV DELTA LOSS	-16337	0	0	0	0	-99	-104	-779	-799	-829	-974	-982	-1069	-1114	-1031	-1061	-982	-910	-842	-780	-722	-667	-548	-2797
NPV TOTAL	120107	0	18	277	1359	1737	2370	3842	4268	5253	5361	5359	5928	5820	6183	6023	5847	5229	4841	4483	4151	3842	3187	36291

CUMULATIVE PRESENT VALUE - NON-TRANSMISSION ($000'S)

	TOTAL	91	92	93	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10	11	12	13-40
CPV CAPITAL		0	18	295	1653	3200	5558	8619	12389	16813	20900	25277	30136	34842	40094	45058	49721	54040	58030	61742	65170	68345	71286	103789
CPV DELTA LOSS		0	0	0	0	-99	-204	-982	-1778	-2607	-3582	-4574	-5643	-6757	-7788	-8849	-9832	-10741	-11584	-12364	-13086	-13753	-14301	-16337
CPV TOTAL		0	18	295	1653	3300	5760	9602	13868	19121	24482	29851	35779	41600	47882	53906	59552	64781	69622	74106	78256	82098	85586	120107

APPENDIX 8

SENSITIVITY STUDIES

SENSITIVITY STUDIES

FIGURES

8-1 NPV COST VERSUS DISCOUNT RATE

8-2 NPV COST VERSUS LONG-TERM ELECTRICITY VALUE

8-3 NPV COST VERSUS LOSS FACTOR

8-4 NPV COST VERSUS 5L46 DIRECT COST

KELLY LAKE - CHEEKYE 500 KV NO. 2 (5L46)

ECONOMIC ANALYSIS

SENSITIVITY TO DISCOUNT RATE

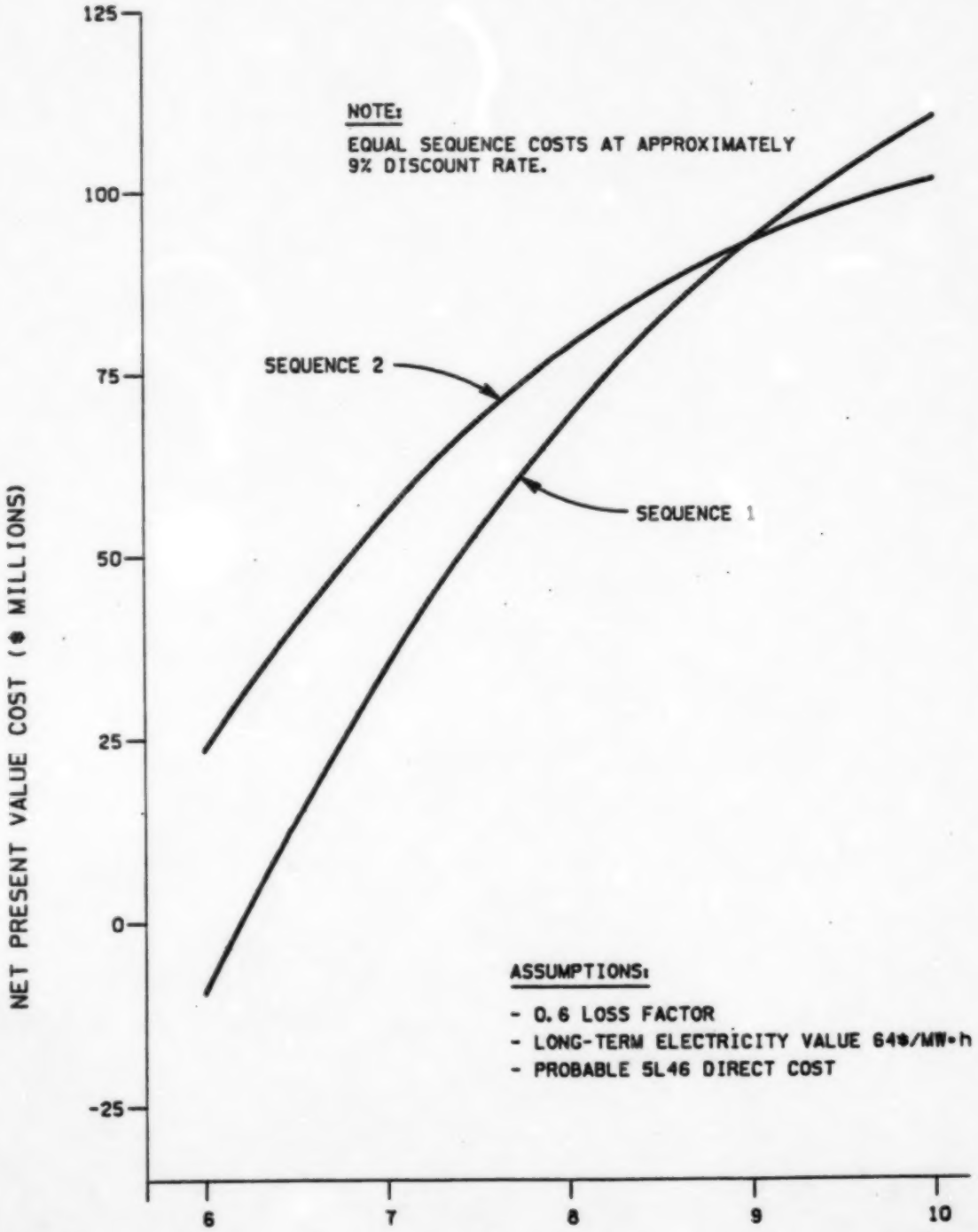


FIGURE 8-1

KELLY LAKE - CHEEKYE 500 KV NO. 2 (5L46)

ECONOMIC ANALYSIS

SENSITIVITY TO LONG-TERM ELECTRICITY VALUE

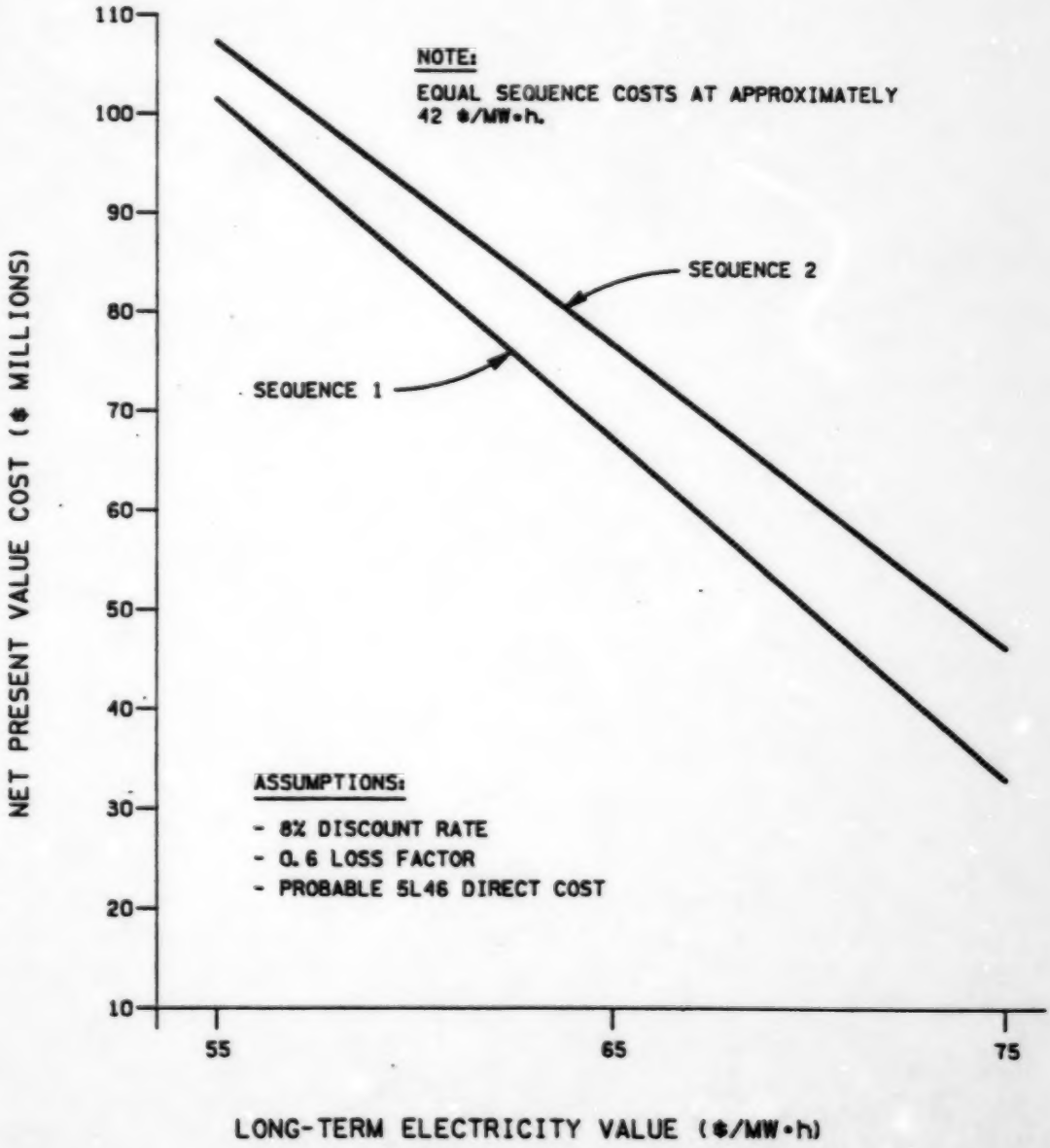


FIGURE 8-2

441/CJS.DGN

KELLY LAKE - CHEEKYE 500 KV NO. 2 (5L46)

ECONOMIC ANALYSIS

SENSITIVITY TO LOSS FACTOR

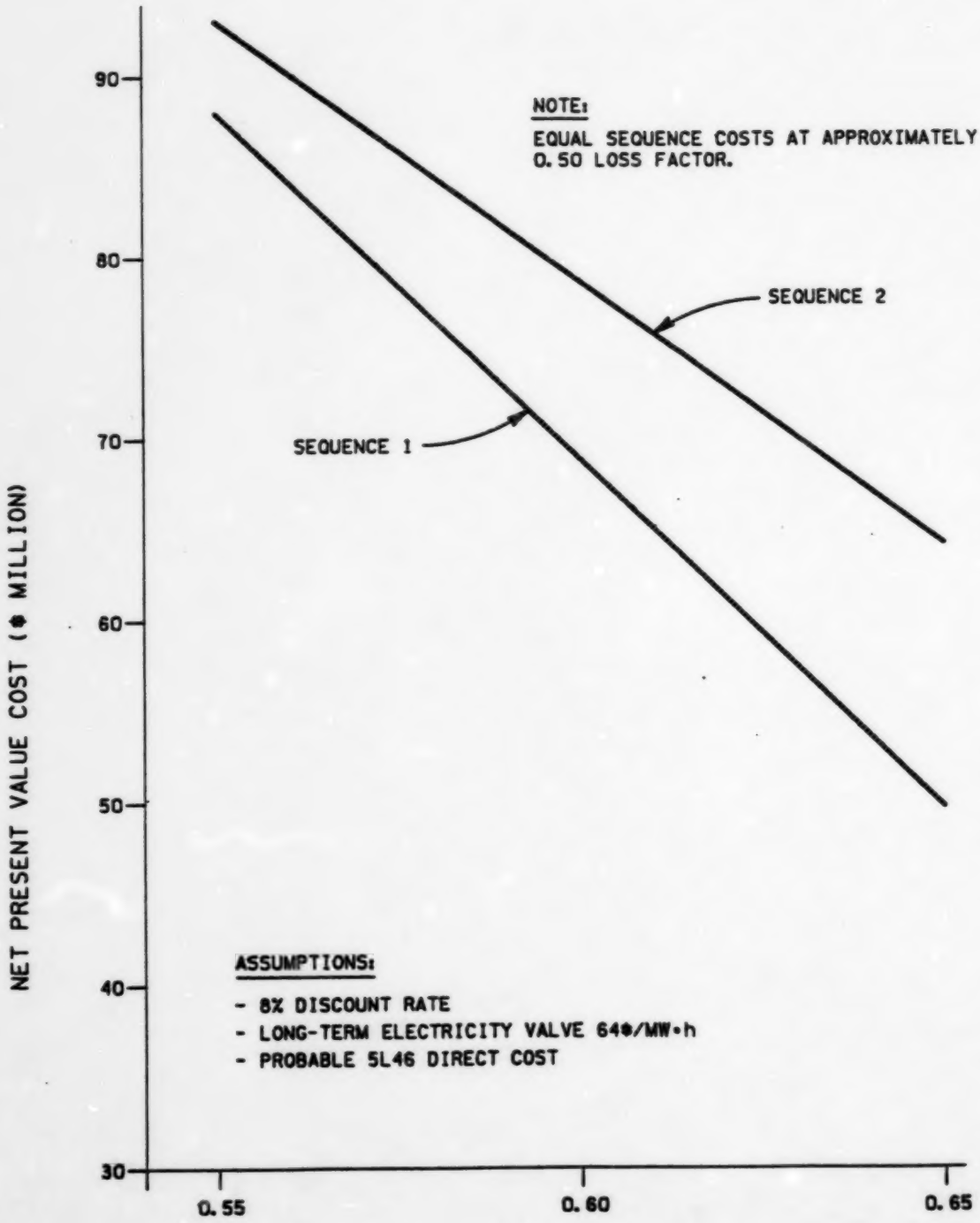


FIGURE 8-3

KELLY LAKE - CHEEKYE 500 KV NO. 2 (5L46)
ECONOMIC ANALYSIS
SENSITIVITY TO 5L46 DIRECT COST

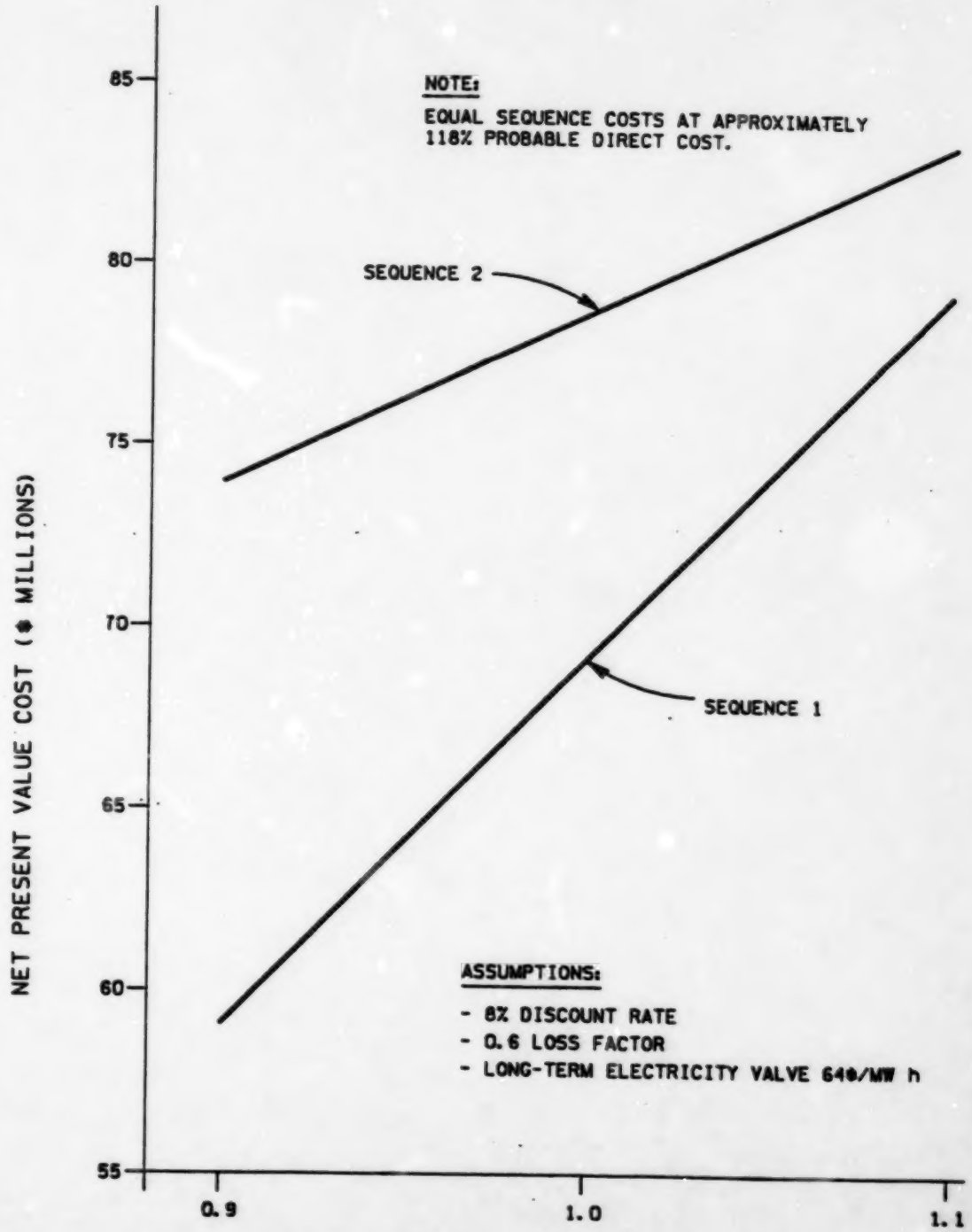


FIGURE 8-4